The Thesis Committee for Neil Rodrigues
Certifies that this is the approved version of the following thesis:

Accounting for Reservoir Uncertainties in the Design and Optimization of Chemical Flooding Processes

APPROVED BY
SUPERVISING COMMITTEE:

Supervisor: ______________________________
Gary Pope

Supervisor: ______________________________
Mojdeh Delshad

Accounting for Reservoir Uncertainties in the Design and Optimization of Chemical Flooding Processes

by

Neil Rodrigues, B.S.

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Dedication

To my parents and my fiancé

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Abstract

Accounting for Reservoir Uncertainties in the Design and Optimization of Chemical Flooding Processes

Neil Rodrigues, M.S.E

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Supervisors: Gary Pope and Mojdeh Delshad

Chemical Enhanced Oil Recovery methods have been growing in popularity as a result of the depletion of conventional oil reservoirs and high oil prices. These processes are significantly more complex when compared to waterflooding and require detailed engineering design before field-scale implementation. Coreflood experiments that have been performed on reservoir rock are invaluable for obtaining parameters that can be used for field-scale flooding simulations. However, the design used in these floods may not always scale to the field due to heterogeneities, chemical retention, mixing and dispersion effects. Reservoir simulators can be used to identify an optimum design that accounts for these effects but uncertainties in reservoir properties can still cause poor project results if it not properly accounted for.

Different reservoirs will be investigated in this study, including more unconventional applications of chemical flooding such as a 3md high-temperature, carbonate reservoir and a heterogeneous sandstone reservoir with very high initial oil saturation. The goal of the research presented here is to investigate the impact that select reservoir uncertainties can have on the success of the pilot and to propose methods to

reduce the sensitivity to these parameters. This research highlights the importance of good mobility control in all the case studies, which is shown to have a significant impact on the economics of the project. It was also demonstrated that a slug design with good mobility control is less sensitive to uncertainties in the relative permeability parameters.

The research also demonstrates that for a low-permeability reservoir, surfactant propagation can have a significant impact on the economics of a Surfactant-Polymer Flood. In addition to mobilizing residual oil and increasing oil recovery, the surfactant enhances the relative permeability and this has a significant impact on increasing the injectivity and reducing the project life. Injecting a high concentration of surfactant also makes the design less sensitive to uncertainties in adsorption.

Finally, it was demonstrated that for a heterogeneous reservoir with high initial oil saturation, optimizing the salinity gradient will significantly increase the oil recovery and will also make the process less sensitive to uncertainties in the cation exchange capacity.

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Nomenclature

λ_j	Mobility of phase 'j'
M	Mobility Ratio
k_v	Vertical Permeability
k_h	Horizontal Permeability
S_{orw}	Residual Oil Saturation to Waterflood
S_{wrw}	Residual Water Saturation to Waterflood
$k_{r,o}{}^{o}$	Corey-Type End Point Relative Permeability to Oil
$k_{r,w}{}^{o}$	Corey-Type End Point Relative Permeability to Water
e_o	Corey-Type Oil Exponent
e_w	Corey-Type Water Exponent
PI	Productivity Index
k_y	y-direction permeability
k_z	z-direction permeability
Δx	Gridblock thickness in x-direction
r_o	Equivalent radius
r_w	Wellbore radius
S	Skin factor
Δz	Gridblock thickness in z-direction
Δy	Gridblock thickness in y-direction
D_s	Retardation Factor
φ	Reservoir porosity
ρ_s	Reservoir rock density
ω_{3s}	Adsorbed concentration of surfactant
C_3	Injected concentration of surfactant
$\dot{\gamma}_{eq}$	Equivalent Shear Rate

n	Power Law Exponent
u	Darcy Velocity
C	Shear Rate Coefficient
$\bar{k}$	Base Permeability
k_{rl}	Relative Permeability of Phase l
S_l	Saturation of Phase l
Q_v	Cation Exchange Capacity (meq/ml-PV)
$\overline{Q_v}$	Cation Exchange Capacity (eq/100g-rock)

CHAPTER 1 : INTRODUCTION

In most conventional reservoirs, approximately 10% of the oil in place is expected to be recovered from the primary phase, with an additional 20-40% of expected recovery from the secondary phase (http://www.fossil.energy.gov/programs/oilgas/eor/index.html). The majority of the remaining oil cannot be extracted economically because it is either trapped by capillary forces, bypassed because of reservoir heterogeneities, or does not have sufficient mobility to flow at reservoir conditions. Therefore, a significant fraction of the oil is available as a target for EOR processes, and the current technology can recover between 30-60% of the original oil in place.

Enhanced oil recovery involves injecting fluids that are not normally present in the reservoir (Lake, 1989) with the objective of improving the sweep efficiency. Chemical EOR (CEOR) involves injecting combinations of alkali, surfactant, and polymer, and has been successfully field tested since at least the 1960's. Other successful forms of EOR include miscible gas injection and thermal methods such as steam or hot water injection. In this thesis, only chemical EOR applications will be studied for various reservoirs with the goal of optimizing the design for maximum oil recovery.

Among the chemical EOR methods, surfactants are used to increase the microscopic displacement sweep efficiency and polymers are used to improve the macroscopic sweep efficiency. A review of the different processes is provided in Chapter 2. The combination of chemicals listed above depends on the amount of residual oil, the initial oil saturation, acid number of the oil, rock properties, reservoir heterogeneities, field operating conditions and fluid properties of the reservoir. With the right design, all these CEOR methods have been successfully proven as a viable technology to recover additional oil that has been left behind at the end of waterflooding.

1.1 MOTIVATION

Chemical flooding is a much more complex process compared to waterflooding and therefore requires detailed engineering design before a successful field-scale implementation. The physical and transport properties of these chemicals are modeled by several equations with parameters that are usually specific to each reservoir. Therefore after identifying suitable reservoir candidates for EOR, the next step in the project is to perform laboratory experiments with test tubes for phase behavior studies and reservoir corefloods to identify the best chemical formulation. Reservoir simulators such as UTCHEM can then be used to match these experiments and obtain parameters for field-scale flooding.

The objective of this research is to use these parameters to study the impact of well configuration, well operating conditions, slug size and chemical formulation on the ultimate oil recovery for ASP, SP and Surfactant floods. Successful laboratory experiments performed on reservoir cores may not always scale-up to the field due to heterogeneities, chemical retention, mixing and dispersion effects. Uncertainties in reservoir properties can be detrimental to the success of the project and must be accounted for in the design. The results of this study can help to identify an optimum, robust design that will account for these reservoir uncertainties.

1.2 DESCRIPTION OF CHAPTERS

In the second chapter, a brief description of chemical EOR processes is provided along with a literature review of field-scale simulations of these processes. The third chapter will investigate the impact of fluid mobility and well-configurations on oil recovery. The fourth chapter will identify parameters that the oil recovery is very sensitive to in a low-permeability, high temperature reservoir, and will then use these results to identify an optimum slug design. The fifth chapter will investigate the impact of alkali consumption and fluid mobility on the success of an ASP pilot project. The sixth chapter will summarize the findings of this research.

CHAPTER 2 : BACKGROUND AND LITERATURE REVIEW

In this chapter, a brief overview of the various chemical flooding processes will be presented along with some definitions that are pertinent to this study. A literature review on some successful field-scale chemical EOR projects and field-scale simulation studies are also presented in this chapter.

2.1 Background of Chemical Enhanced Oil Recovery Processes

The use of chemicals to improve the sweep efficiency of flooding processes has been studied for quite some time, but has recently gained interest due to higher oil prices and increasing effectiveness of the injected chemicals. Additionally, computational advancements in recent years have made it possible to perform more complex simulations in shorter amounts of time, thereby significantly enhancing the understanding of EOR processes. Included below is a brief description of the CEOR processes studied in this thesis.

2.1.1 Polymer Flooding

In cases where the mobility of the displacing phase is higher than the mobility of the phase being displaced, the displacing phase may bypass the displaced phase. This process results in viscous fingers being developed, which in turn can lead to lower sweep efficiency. To suppress this effect, polymer is injected to increase the viscosity of the displacing water phase so that the overall mobility of the displacing phase is equal to or lower than the mobility of the displaced phase. This is one of the most common methods of enhanced oil recovery, with about one billion pounds of polymer used for EOR in 2011 (Pope, 2011). HPAM is more commonly used in field applications since it is cheaper and less susceptible to bio-degradation. An added advantage of HPAM is that its price relative to crude oil has decreased since the 1960's, while the product quality has improved. It has also been shown that polyacrylamide can be modified by adding monomers to make the molecule less sensitive to salinity and temperature (Levitt et al, 2008; Vermolen et al. 2011).

In addition to improving the sweep efficiency, some research has also shown that the visco-elastic nature of HPAM can help to reduce the residual oil saturation to values below the waterflood residual oil saturation. This has been demonstrated in laboratory corefloods (Wreath, 1989; Wang, 1995; Wang, 2000) and a theoretical explanation into the mechanisms that can lead a reduction in residual oil saturation is provided by Huh and Pope (2008).

2.1.2 Surfactant-Polymer (SP) Flooding

Surfactants are used to lower the interfacial tension (IFT) between the water (displacing phase) and oil (displaced phase), thereby increasing the microscopic displacement sweep efficiency. The amount of residual oil that can be mobilized has shown to be correlated with the 'Capillary Number' (Chatzis and Morrow, 1984), which is defined as the ratio of viscous forces to capillary forces. Taber (1969) has shown that it is possible to displace almost all the residual oil provided that the capillary number can be increased by 3-5 orders of magnitude. Developments in surfactant technology have progressed remarkably since the early days of surfactant flooding and it now possible to use cost-effective surfactants that are both stable in harsh environments and can reduce the IFT by up to five orders of magnitude. Polymer is usually added to the chemical slug to improve the macroscopic sweep of the injected fluid and is also injected as a buffer solution after the SP slug to ensure that the injected chemicals are displaced effectively though the reservoir.

To date, most field tests of SP processes have been performed in sandstone reservoirs and anionic surfactants are preferred since they are repelled by the negative charge associated with sandstone surfaces at neutral pH. This leads to lower adsorption of the surfactant. Hirasaki et al. (2008) have provided a detailed description of the advancements in surfactant technology. Adkins et al (2010) and Lu et al. (2012) have highlighted how it is now possible to tailor a surfactant for use with any crude oil in harsh environments of temperature and salinity, without significant incremental cost.

2.1.3 Alkaline-Surfactant-Polymer (ASP) Flooding

Alkali provides multiple advantages when injected with an ASP slug and is relatively inexpensive when compared to the cost of synthetic surfactants and polymers. Provided the crude oil has a sufficiently high amount of naphthenic acids, alkali can be used to generate a hydrophobic in-situ soap which, just like a synthetic surfactant, can lower the IFT by several orders of magnitude. Additionally, the injected alkali generates a negative charge on the rock surface, leading to lower adsorption of anionic surfactants. This means that a much smaller amount of synthetic surfactant is required to mobilize the trapped oil in an ASP process, thereby reducing the incremental cost per barrel of oil. On top of these two main advantages, alkali also improves microemulsion phase behavior and lowers the salinity requirement.

2.2 Important Terms and Definitions

Lake (1989), Green and Willhite (1998) and Sorbie (1991) provide an excellent reference into understanding the theory behind different EOR processes. In this section, some of the definitions that are pertinent to this thesis will be discussed.

2.2.1 Mobility Ratio

The mobility in a multi-phase system is defined as the ratio of the relative permeability to the viscosity of that phase:

$$\lambda_j = \frac{k_{rj}}{\mu_j}$$

The mobility ratio is then defined as the ratio of the mobility of the displacing fluid to the mobility of the displaced fluid. The mobility of each of these fluids can be calculated by adding up the relative mobility of each phase. The mobility ratio can then be expressed as

$$M = \frac{\left(\lambda_1 + \lambda_2 + .. + \lambda_j\right)_{displacing}}{\left(\lambda_1 + \lambda_2 + .. + \lambda_k\right)_{displaced}}$$

From the definition above, if the mobility ratio is less than unity, the displacement process will be stable. If not, this can lead to fingering and poor sweep efficiency of the injected fluid.

2.2.2 Salinity Gradient

A salinity gradient is critical for the success of any surfactant process and is used to control the phase environments of the surfactant slug and polymer drive (Hirasaki et al., 1983). In a normal gradient, the reservoir salinity is over-optimum, the surfactant or alkali is injected at optimum salinity and the polymer drive is under-optimum. In an unfavorable salinity gradient, the only difference is that the reservoir salinity is initially under-optimum. This second type of salinity gradient is unfavorable because consumption or dilution effects of the injected salt can lead to the salinity of the surfactant slug being under-optimum. Additionally, uncertainties in the oil composition or reservoir conditions could lead to changes in the phase behavior and to the Type III salinity window being higher than what was estimated in the laboratory. Therefore, with the unfavorable salinity gradient the low-IFT Type III salinity environment may not be reached, whereas with the normal salinity gradient the salinity will always pass through the Type III region.

2.2.3 Ion Exchange Capacity

Clay minerals tend to have negatively charged sites on its surface that are countered by cations from the reservoir fluid. The exchange capacity is a measure of these excess negative charges. It has also been shown by Bunge and Radke (1985) that for a mass-action model that uses a single average equilibrium constant to describe the exchange with a mineral site, the hydrogen exchange capacity (HEC) and cation exchange capacity (CEC) are equal to the total number of mineral sites. deZabala et al. (1982) have shown that the exchange capacity can result in temporary consumption of alkali, which in turn can hurt the success of the flood.

2.3 Review of Field-Scale Chemical Floods

From very early on it was recognized that reservoir heterogeneities and capillary forces can reduce the effectiveness of a waterflood, and that additives would be required to overcome these effects. One of the first patents to highlight the use of water-soluble additives to improve the mobility ratio was issued to Detling (1944) and the use of HPAM to improve oil recovery was first patented by Pye (1963). Since then, several successful field-scale polymer floods have been reported in the literature.

In the Courtenay sand of the Chateaurenard field, Takagi et al. (1992) have reported that the cumulative oil recovered was more than 100% of the remaining oil in place inside the pilot area. The well configuration in this pilot was an inverted five-spot (with four producers and one central injector), which implies that the high recoveries are a result of oil being produced from outside the pilot area. In the Al Khlata formation of the Marmul field, Koning et al. (1988) has reported that an incremental 46% of STOIIP was recovered, also using an inverted 5-spot well configuration. In one of the largest polymer flood field applications, Wang et al. (2002) have reported 12-15% incremental oil recovery of STOIIP at the Daqing field, with some areas showing recovery values as high as 20% of STOIIP (Wang et al., 2008). They have also reported that the cost of polymer flooding in their field was lower than the cost of water flooding, due to higher oil production and lower produced water processing costs as a result of the low water cut.

The use of chemicals to lower interfacial tension was first patented by Atkinson and Adams (1927) but it discovered soon after that permeability heterogeneities might hinder the effectiveness of the injected solution. The Maraflood process was one of the first commercially successful miscible flooding processes, with multiple field tests being initiated in the Robinson sands of Southern Illinois since as early as 1962. Earlougher et al. (1976) reported one of the first economic successes with the Maraflood process at the 119-R field test, with approximately 50% of remaining oil in place recovered.

In the Loudon Field in the Illinois basin, Exxon conducted a series of SP pilot tests with reported recoveries as high as 60% of waterflood residual oil (Bragg et al., 1982), in spite of bacterial degradation of the biopolymer used in the slug and the presence of high-salinity formation brine. More recently, Sharma et al. (2012) have reported an increase in average oil cut from 1% to 12% at the Lawrence field in the Illinois Basin, where a multiple 5-spot pilot project was initiated by Rex Energy. It was observed that the poor response in some patterns was a result of poor chemical confinement, with confined patterns showing oil cuts upward of 20%.

Nelson et al. (1984) showed how to avoid field-scale problems of poor alkali propagation and uncertainties in the soap phase behavior by using a co-surfactant with a higher salinity requirement for Type III phase behavior. Falls et al. (1994) have then demonstrated the feasibility of this process in the White Castle field in Louisiana. It was reported that approximately 38% of waterflood residual oil was recovered in spite of the absence of polymer for mobility control.

Other successful ASP field tests have been reported by Qi et al. (2000) where an incremental 24% OOIP recovery was observed on multiple inverted 5-spot patterns in the Karamay Oil Field in China. Shutang and Qiang (2010) summarize the results of different ASP floods in the Karamay, Daqing and Shengli fields. The incremental oil recovery for these ASP floods range from 13.4% - 35.3% of OOIP.

2.4 Review of Field-Scale Chemical Flooding Simulations

The previous section highlights the promise being shown by chemical flooding as a viable technology to recover additional oil. This, in turn, has led to an increased interest in the simulation of these EOR processes. Reservoir simulators can be used to both design chemical floods and understand them through history matching of field results. Numerous studies have shown how it is possible to design robust field-scale floods by accounting for reservoir uncertainties.

Takagi et al (1992) provided a good match of the Chateaurenard polymer flood described in the previous section. After performing sensitivity studies, they concluded that the polymer flood performance was dominated by polymer adsorption. Their results showed very little sensitivity to changes in the permeability distribution or to grading the polymer drive slug.

Huh et al. (1990) matched three of the Loudon SP pilot tests and found that lower concentrations of polymer used in the larger-spacing pilots led to poor polymer propagation which in turn hurt the flood performance. Saad et al. (1989) simulated the

Big Muddy surfactant pilot in Wyoming and were able to use the simulation results to interpret the pilot. One of the key findings from the simulations was that calcium pickup from the clays caused the salinity in the surfactant slug to shift from the Type I environment to the Type III environment, thereby resulting in IFT reduction and residual oil mobilization. In a follow-up paper, Saad et al. (1990) used the findings from the pilot simulations to improve the design without significant increase in cost and showed an increase in recovery from 30% to 60% of waterflood residual oil.

Several design and optimization studies have also been performed with chemical flooding processes. Wu et al (1996) present a study using horizontal wells and found that a larger, dilute slug showed higher Net Present Value (NPV) because of the deferred chemical cost. They also highlighted the importance of a short project life and higher polymer concentrations to improve the economics. Anderson et al (2006) performed an optimization study on a mixed-wet dolomite reservoir and looked at the impact of surfactant and polymer concentration and slug size, salinity, chemical adsorption, vertical permeability and capillary desaturation curves on the oil recovery and NPV.

Many studies on improving the modeling of chemical flooding processes have also been performed. Mohammadi (2008) provided a detailed study into the mechanistic modeling of ASP processes and performed studies to optimize the design of a pilot-scale flood. Veedu (2010) demonstrated the impact that grid refinement can have on the propagation of surfactant and salt in the reservoir. It was shown that the surfactant and salt can get artificially diluted if a coarse simulation grid is used, and this can lead to salt propagating below the Type III window or surfactant propagating below the critical micelle concentration (CMC).

CHAPTER 3 : IMPACT OF FLUID MOBILITY AND WELL-CONFIGURATION ON A SURFACTANT-POLYMER PILOT

This chapter will focus on the impact of different well-configurations on the success of a multi-pattern pilot. The relative permeability and viscosity of the reservoir fluids dictate how efficiently the oil-bank moves from the injector to producer. Uncertainties in the relative permeability curves can lead to lower relative permeability to oil and can have a significant impact in reducing the mobility of the oil-bank. The impact of this reduction in mobility on each of these well-configurations was also investigated. The overall goal of this study was to identify a well-configuration that will maximize chemical efficiency and to identify a strategy to minimize the sensitivity to the oil-bank mobility.

3.1 SIMULATION MODEL

The reservoir in this study is a 900ft deep sandstone reservoir with two main sand deposits that will be flooded. The upper sand is approximately 7ft and has an average permeability and porosity of 138md and 17.6% respectively. The lower sand is approximately 9ft and has an average permeability and porosity of 203md and 20.1% respectively. Since the lower sand has higher permeability, it has also been waterflooded more extensively compared to the upper sand. The oil saturation before SP flood is 36% and 31.5% in the upper and lower layers respectively. All geological data such as permeability, porosity, gridblock thickness and initial water saturation were provided by the operator. The water saturation was then matched on a regional basis to match the field oil production data provided by the operator.

The pilot area is approximately 15 acres and contains six repeating normal 5-spot patterns. The entire simulation model, however, is approximately 100 acres with the pilot wells located in the middle of the grid. The simulation model is approximately 2625ft x 1715ft x 16.11ft. The gridblock size is 35ft x 35ft x 1.84ft in the first four layers, and 35ftx35ftx1.75ft in the last five layers. Figure 3-1 and Figure 3-2 are maps of the permeability field in the first and ninth layers and also illustrates the location of the pilot area. From the permeability map, it can be seen that the reservoir pinches out both north and south of the pilot area. However, in the lower sand facies, the reservoir pinch out is further away from the pilot area and therefore is more susceptible to fluid loss off-pattern. The oil saturation in the first and ninth layers is illustrated in Figure 3-3 and Figure 3-4 respectively. More details about the simulation model and fluid properties are summarized in Table 3-1.

Boundary wells have also been added to eastern and western boundaries of the simulation grid. These wells are pressure-constrained and are set to 300 psi, which is approximately equal to the initial reservoir pressure before flooding. Some sensitivity simulations will also be performed by adding more boundary wells closer to the pattern to help with chemical confinement and to observe the corresponding effect on oil recovery.

A history match of the phase behavior and coreflood experiments was already performed for this formulation. The parameters obtained from this match were used for the field-scale simulations and are shown in Table 3-2. Finally, from a single-well tracer test, the residual oil saturation to chemical was estimated to be 8%.

The injector wells for the normal 5-spot pattern are injecting at a constant rate of 125 BPD. The bottom-hole pressure of the pilot producer wells for all the simulations is set at 25 psi, which is approximately equal to the field operating conditions. It is important to set the producer well as pressure constrained in order to accurately capture the production of the oil bank. Since the mobility of the oil bank is lower than the mobility of the high water-cut fluid ahead of it, the flow rates at the producer are going to drop as this viscous oil bank is being produced. Simulating the producer with constant flow rate might over-predict the recovery and also will result in unrealistic simulated bottom-hole pressures at the producer.

3.2 BASE CASE SIMULATION

In the base case simulation, the well-pattern contains six repeating normal 5-spot patterns. A map of the pilot wells is provided in Figure 3-7. In this figure, the wells with blue markers represent injector wells and the wells with green markers represent producer wells. Inside the pilot area, there are twelve injectors, six producers and one observation well.

The injection scheme implemented in the field included 0.35 PV of 1% surfactant, 1 PV of polymer drive and 1 PV of water. More details about the chemical composition of the different slugs are provided in Table 3-3. The polymer concentration in the SP and polymer drive slugs was calculated to ensure that the displacement of the oil and microemulsion bank is stable. Gogarty et al (1970) described how the relative mobility of the miscible slug has to be lower than that of the oil bank for a stable displacement, and that the minimum mobility of the oil bank should be designated as the design mobility of the SP slug. The actual mobility of the oil bank might be higher depending on the amount of oil left in the reservoir and the saturation of the oil bank. However, using the minimum mobility as the design mobility provides a safety factor. The polymer viscosity requirement can be calculated by taking the inverse of the minimum mobility of the oil bank. In this calculation, it is assumed that the relative permeability end-point for the microemulsion slug is 1 and the mobility ratio between the SP slug and the oil-water bank is 1.

A plot of the minimum mobility and corresponding polymer requirement is shown in Figure 3-5. It can be seen that the polymer requirement is approximately 17cp. The polymer viscosity in the SP slug was chosen to be 18cp. Similarly, assuming that the relative permeability end-points are both equal to 1 in the SP slug and polymer drive, the polymer viscosity in the drive should be higher than the microemulsion viscosity. A plot of the microemulsion viscosity is shown in Figure 3-6. Since the oil concentration in the microemulsion phase is variable throughout the reservoir, the maximum viscosity of approximately 41cp was used as the design criterion. The viscosity of the polymer drive was assumed to be 42cp.

The results of this simulation are shown in Figure 3-8 and Figure 3-9. The base case simulation shows recovery of approximately 78,800bbls of oil, which is approximately 70.8% of the remaining oil-in-place. Figure 3-10 and Figure 3-11 show the oil saturation at the end of the water drive. It can be seen that the last layer has better sweep than the first layer, and this is mostly due to the fact that the lower layer has a higher permeability and is relatively more homogeneous.

3.3 Impact of Well-Configuration on Oil Recovery

From the results of the base case simulation, it can be seen that oil is even mobilized away from the pattern since most of the injectors in this pattern are not fully confined. The goal of this section was to look at producing this reservoir with alternative well-patterns in order to improve the chemical confinement. This, in turn, will improve the chemical efficiency.

3.3.1 Inverted 5-spot configuration

In this configuration, the injector wells were replaced by producer wells, and vice-versa. A map of this configuration is shown in Figure 3-12. The rates for the injector wells are still operating at 125 BPD in order to maintain injection pressures similar to the base case. The size and composition of the slugs were kept the same as the base case. This run is referred to as Inv_1 and results of this simulation are shown in Figure 3-13 and Figure 3-14.

The results of this simulation show that 91,000 bbls of oil was recovered, which is nearly 82% of the oil in place. The additional 12% of OIP that was recovered by using an inverted 5-spot pattern means that the chemical efficiency is higher, and can even be optimized to improve the project economics. It can also be seen in Figure 3-15 that some of the oil is even mobilized outside the pilot area. The oil that is being produced at the wells that are on the periphery of the pilot area is not confined. Since the mobility of the oil-bank is low, the drawdown at the producer might not be sufficient to produce all of this oil. And since the oil-bank is being 'pushed' by a large polymer slug, some of this oil will move outside the pilot area. However, even though some of this oil moves off-pattern, most of it still gets produced, as indicated by the high recovery factor. This results in a longer 'tail' in the produced oil-cut profile when compared with the base case simulation.

3.3.2 Normal 5-spot pattern with boundary wells

In this simulation, the well-configuration inside the pilot area and the injection scheme is the same as the base case. The only difference is the addition of boundary water injector wells to help confine some of the injected fluid. From the oil saturation map of the base case simulation (Figure 3-11) it can be seen that there is some fluid loss on the western and north-eastern areas of the pilot. It was proposed by the operator to add water injectors to suppress some of this off-pattern chemical loss. These peripheral water injectors were set at 125 BPD and the salinity of this injected water was kept the same as the salinity of the pilot injectors. This would minimize interference with the salinity gradient in the pilot area. This simulation is referred to as Base_2 and the well-configuration is shown in Figure 3-16. The results are shown in Figure 3-17 and Figure 3-18.

The results show that the recovery increased to 80,600 bbls of oil, which is approximately 72.4% of the oil in place. This is an increase of 1.6% from the base case simulation. A map of the oil saturation after the water drive is shown in Figure 3-19. When compared against the base case oil saturation map in Figure 3-11 it can be see that the oil saturation outside the pilot area on the eastern and western portions of the model is lower in the Base_2 simulation.

In order to quantify how much the boundary wells assisted with improving the chemical confinement, a unique tracer was added to the SP and Polymer drive slugs in both the base case and Base_2 simulations. In the base case simulation, 61.7% of the tracer injected in the SP slug was produced back. If one assumes that the contribution of the injected fluid to the pilot area is 25% for the four corner injectors, 50% for the six remaining injectors on the pilot area boundary, and 100% for the two injectors in the middle of the pilot area, one can expect 50% of the total injected fluid to be produced back. The base case simulation shows better tracer recovery because of the presence of a reservoir pinch-out to the north and south of the pilot area. In the Base_2 simulation, 66.3% of the SP tracer is produced back, indicating that the peripheral water injectors did help with the chemical confinement.

Similarly, 36.2% of the polymer drive tracer was produced back in the base case and 38.3% was produced back in the Base_2 simulation. The recovery of the polymer drive tracer is lower than the recovery of the SP tracer because of the poor mobility ratio between the water chase and polymer drive. The water is not able to displace the polymer solution as well as the polymer drive is able to push out the SP solution.

3.3.3 Inverted 5-spot configuration with boundary wells

In this simulation, the well-configuration inside the pilot area is the same as the one in simulation run Inv_1. However, boundary water injector wells were added to capture some of the oil that has been pushed off the pilot area. The well-configuration is shown in Figure 3-20 and this simulation will be referred to as Inv_2.

The results are shown in Figure 3-21 and Figure 3-22, along with a map of the oil saturation after the water chase in Figure 3-23. From these figures it can be seen that the boundary wells do help with producing the oil that is pushed off-pattern. The cumulative oil increases to approximately 94,000bbls, which is an increase in 2.74% of the OIP.

Similar to the Base_2 simulations, a unique tracer was added to the SP and Polymer drive slugs to quantify the amount of chemical confinement. In the Inv_1 simulations, the recoveries of the SP and polymer drive tracers are 81.8% and 50.8%. These recoveries are much higher than the base case because the injectors have better confinement. As discussed earlier, there is still some fluid loss off-pattern but it is not as much as the base case simulation. This was expected since in order to have one completely confined injector, the pilot area must have a minimum of 3x3 repeating inverted 5-spot patterns. Since the configuration in Inv_1 has only 3x2 repeating inverted 5-spots, none of the injectors are fully confined. After adding the peripheral water injectors, the recoveries of the SP and polymer drive tracers are 87.5% and 58.1%.

3.4 Impact of Oil-Bank Mobility on Well-Configuration

One of the key parameters in identifying an optimum flood design is the relative permeability of each phase. In this thesis, Corey-Type functions are used to model the relative permeability to the water, oil and microemulsion phases. It was demonstrated in the previous section how the relative permeability curves can be used to calculate the minimum mobility, which in turn can be used to calculate the polymer requirements for a stable displacement process. However, these parameters are usually measured in the laboratory and may not be fully representative of the field. For this study, the impact of reducing the oil bank mobility was investigated for different well-patterns.

3.4.1 Fractional Flow Theory

From fractional flow theory, the oil bank mobility will decrease either by reducing the relative permeability end-point to oil or by increasing the relative permeability exponent to oil. The oil-bank mobility will also decrease by increasing the relative permeability to water or by lowering the oil viscosity. In the simulations performed in this section, the relative permeability exponent to oil was increased from 2 to 4. Figure 3-24 and Figure 3-25 illustrate the fractional flow curves for these two scenarios and the corresponding effect on oil bank breakthrough. With the exception of the relative permeability exponent of oil, all other relative permeability parameters are identical to those described in Table 3-1 and Table 3-2.

From the oil-cut profiles, it can be seen that reducing the oil-bank mobility will lead to a delayed breakthrough but also a higher oil-cut, keeping the volume of oil recovered the same. However, the equations behind fractional flow theory are derived by assuming one-dimensional linear flow, no dispersion effects, constant chemical mass and adsorption. There are many additional assumptions that are discussed by Pope (1980). Therefore, this scenario of reducing the oil-bank mobility was simulated with UTCHEM to look at the corresponding effect on a three-dimensional, heterogeneous, multi-well pattern.

3.4.2 Repeating Normal 5-spot Pattern

In this simulation, the only change from the base case simulation is the increase in oil exponent at the low capillary numbers from 2 to 4. All the slug sizes and operating conditions were kept the same. This run is referred to as N_exp4 results of this simulation are shown in Figure 3-26 and Figure 3-27.

From these charts it can be seen that the overall trend of the oil-cut profile is similar to the one obtained from fractional flow theory. By increasing the oil exponent, the oil bank breakthrough is delayed and the oil cut has increased. The total production rate drops more in this simulation when compared to the base case since the mobility of the bank has now been reduced. It is therefore harder to produce this oil bank since the constant portion of the producer productivity index stays the same. The oil cut and breakthrough time is different from fractional flow theory because of the reservoir heterogeneities, variable initial oil saturation, variable chemical concentrations, mixing effects, dispersion and many other effects. However, it is important to note that the difference in cumulative oil recovered between these two simulations is 6300 bbls, whereas fractional flow theory shows that the recovery should be the same.

This result could be explained by the fact that the decrease in oil bank mobility means that mobility ratio between the SP slug and the oil-bank may be greater than 1. Also, since the oil-bank is harder to produce and because the injectors are set to rate constraint, pressure will build up behind the oil bank and more fluid will be lost off-pattern since it is harder to inject inside the pattern. Similar to the studies performed in the previous section, a tracer was injected with the SP and polymer drive slugs to understand fluid movement inside the simulation model. In the base case simulation, 61.7% of the SP tracer is produced back where as 60.7% is recovered in this simulation.

An additional simulation was performed, referred to as N_exp4_2, where the polymer viscosity in the SP and polymer drive was increased to maintain a stable displacement process. The polymer concentrations were determined using the same procedure as the one used for the base case, with 25cp in the SP slug and 52cp in the polymer drive. The results are also shown in Figure 3-26 and Figure 3-27.

From these charts, it can be seen that the cumulative oil recovery is the same for run N_exp4_2 and the base case. The cumulative recovery in this simulation is 78,600 bbls, which is 0.2% lower than the base case. The amount of SP tracer recovered in this simulation was 58.3%, which is lower than both N_exp4 and the base case. There is more fluid lost off-pattern in this scenario because the pressure build-up in the pattern is greater than in the previous two simulations because of the higher polymer viscosity. However, even though more fluid is lost off-pattern, the oil recovery in N_exp4_2 is almost the same as the base case. This implies that the difference in recovery observed when the oil exponent is increased is mostly due to the displacement process being unstable. In this scenario, the off-pattern fluid loss has little impact on the recovery since the oil inside the pattern is confined.

3.4.3 Repeating Inverted 5-spot Patterns

Simulations similar to N_exp4 and N_exp4_2 were performed on the inverted 5-spot configuration. In I_exp4, the only difference from Inv_1 is that the oil exponent is increased from 2 to 4 (similar to run N_exp4). In I_exp4_2, the oil exponent and polymer concentration are increased (similar to run N_exp4_2). The results are shown in Figure 3-28 and Figure 3-29.

It can be seen from these charts that this well-configuration is more sensitive to changes in the oil mobility than the normal 5-spot simulations. When the oil exponent was increased and the polymer concentration was raised to maintain a stable displacement, the cumulative oil recovery was almost the same for the runs N_exp4_2 and the base case. With the inverted 5-spot patterns, when the oil exponent is increased the cumulative oil recovery decreases in a similar fashion observed in the normal 5-spot simulations. The difference between the Inv_1 and I_exp4 simulations is 11,345 bbls. However, when the polymer concentration was increased in I_exp4_2 to maintain a stable displacement design, the oil recovery is still lower than Inv_1 by 6,592 bbls. The reason for this is because the oil in the pilot area is not completely confined.

The results imply that the reduction in oil recovery that is observed in the simulation I_exp4 was because of both sweep efficiency and off-pattern losses. The tracer recovery in the Inv_1, I_exp4 and I_exp4_2 simulations are 81.8%, 80.4% and 79.0%. Since the polymer concentration in I_exp4_2 is higher, the mobility of this fluid is lower than that in Inv_1 and I_exp4, which is why less of the injected fluid is produced back. When the oil bank mobility is reduced, the producers on the periphery of the pilot area are not able to capture the same volume of oil compared to the run Inv_1, and some of this oil is pushed off pattern. However, because of the higher chemical efficiency in the inverted 5-spot pattern, all these three simulations still recover more oil than the simulations using the normal 5-spot configuration.

3.4.4 Normal 5-spot with Boundary Injectors

The results from Base_2 indicate that better chemical confinement through boundary injectors can improve the oil recovery. The goal of this next simulation was to investigate the impact that these boundary wells will have on recovery when the oil mobility is reduced. This run will be referred to as N_exp4_3 and the well configuration and operating conditions are identical to the Base_2 simulation. The only difference is that the oil exponent is increased from 2 to 4. The results are shown in Figure 3-30.

The results show that while oil recovery in this simulation does increase, the boundary injectors do not significantly assist with reducing the sensitivity to the oil mobility. When the oil exponent is increased, the difference in recovery is 7000 bbls for the well-configuration with boundary injectors and 6300 bbls for the configuration without boundary injectors. So while the boundary injectors do help to recover additional oil, the advantage of extra chemical confinement does not offset the poorer sweep efficiency when the oil exponent is increased.

3.4.5 Inverted 5-spot with Boundary Injectors

The results from I_exp4 and I_exp4_2 show that the inverted 5-spot pattern is more sensitive to changes in the oil bank mobility than the normal 5-spot pattern. The purpose of this simulation was to study the sensitivity of increasing the oil relative permeability exponent on an inverted 5-spot configuration with boundary wells to capture some of the oil that has been pushed off-pattern. The simulation will be referred to as I_exp4_3, and the well-configuration is identical to the one used in the simulation Inv_2. The only difference is that the relative permeability exponent for oil at low capillary number was increased from 2 to 4. The results are shown in Figure 3-31.

The results of this simulation show that while the boundary injectors do help to recover additional oil, it does not seem to have a significant impact on reducing the sensitivity to the oil bank mobility. When the oil exponent is increased, the difference in recovery is 11,700 bbls for the configuration with boundary injectors and 11,300 bbls for the configuration without boundary injectors. The same trend was observed with the normal 5-spot simulations.

3.4.6 Sensitivity to Oil Relative Permeability Exponent at High Capillary Number

Table 3-2 lists the relative permeability parameters at high capillary number that was used in the base case simulation. It was assumed that the exponent of the oil relative permeability was equal to 1 at high capillary number conditions. Two simulations were performed on the base case and Inv_1 pattern where the only change was increasing the oil exponent from 1 to 2. The results are shown in Figure 3-32 and Figure 3-33.

The results for both the well-configurations show that the oil recovery decreases when the oil exponent is increases. The fractional flow curves for these two scenarios are illustrated in Figure 3-34. From this plot it can be seen that the displacement is no longer piston-like, and that the oil cut profile has a 'tail' after the breakthrough of the oil bank. This profile illustrated in Figure 3-35 and shows that the oil-cut only drops below 1% after 3 PV has been injected. Since the slug sizes in this simulation are not that large, this explains why some of the oil is left behind.

It is not economical to inject such large slug volumes in order to mitigate this effect, especially since there is a lot of uncertainty about this parameter. However, injecting a larger concentration of polymer can help increase the recovery without very large slug sizes. This is illustrated in the fractional flow curves and oil-cut profiles in Figure 3-36 and Figure 3-37.

To construct this new set of fractional flow curves, the polymer viscosity was increased from 18 cp to 25 cp. The oil exponent at high capillary number is equal to 2 for both curves. It can be seen that the oil bank will now break through earlier and will also have a larger oil-cut (compared against the scenario with 18 cp slug viscosity). This scenario was simulated with UTCHEM and the results are included in Figure 3-32 and Figure 3-33.

As the polymer concentration increases, more of this oil will be recovered. In this example, 25 cp was only chosen because the same concentrations of polymer were used in simulation runs N_exp4_2 and I_exp4_2. Since the oil exponent at high capillary number is very uncertain, it is very difficult to design and optimize for this parameter. The goal of this part of the study, therefore, was to illustrate how injecting a polymer concentration slightly above the minimum requirement for a stable displacement process will help to reduce the sensitivity this uncertainty.

Figure 3-32 shows that injecting a larger surfactant slug with the same total mass of surfactant can also help to increase recovery. However, injecting very dilute slugs may result in the surfactant propagating below the critical micelle concentration and can also be adsorbed completely. Also, since the concentration of polymer in the SP slug stays the same, this scenario involves injecting a larger polymer mass while also increasing the project life.

3.5 CONCLUSIONS

The goal of this chapter was to investigate how fluid mobility and well-pattern can affect the oil recovery of a SP Pilot. The results show that a repeating, inverted 5-spot pattern has better chemical efficiency and recovers more oil than a repeating, normal 5-spot pattern for this reservoir, even though the oil is not completely confined in an inverted 5-spot pattern. An inverted 5-spot pattern will be less sensitive to heterogeneities outside the pilot area when compared to a normal 5-spot pattern. The drawback to using an inverted 5-spot pattern is that it can take longer to inject the same slug sizes as a normal-5spot pattern. However, simulations should be performed with pressure-constrained injector wells to quantify if, and by how much, the project life increases. Also, since the chemical efficiency is higher for an inverted 5-spot, the same slug sizes used in a normal 5-spot might not be needed.

It was also demonstrated how boundary wells can be used to reduce the amount of chemical that is lost off-pattern. In the normal 5-spot configuration, the use of boundary injectors helped to increase the recovery by 1.6%, and in the inverted 5-spot configuration the recovery increased by 2.7%.

Simulations were also performed to investigate how the oil-bank mobility affects each of these pattern configurations. In this study, an increase in the oil exponent was used to reduce the oil-bank mobility, but other relative permeability parameters will also show similar results. It was observed that the normal 5-spot pattern is less sensitive to a reduction in the oil-bank mobility. Since the oil is not completely confined for an inverted 5-spot configuration, a reduction in oil-bank mobility will cause some of the fluid to move away from the producers since it is being displaced by a polymer solution. Most of this oil-bank will still be produced, but some of it may move off-pattern. The use of boundary water injectors can help to recover some of this oil.

The reduction in oil bank mobility also means that if the base case polymer concentrations are used, the displacement process is now unstable. Also, in a normal 5-spot configuration, the reduced mobility of the oil bank could lead to pressure building up behind the oil bank (since it is now harder to produce) and subsequently to some of the injected fluid being lost off-pattern. It was demonstrated that when the polymer requirements are increased to ensure that the displacement process is stable at the reduced mobility conditions, the oil recovery in the normal 5-spot configuration is very close to the base case oil recovery. This implies that even though some of the injected fluid is lost off pattern when the mobility is decreased, this does not contribute significantly to the reduction in oil recovery. In the inverted 5-spot configuration however, while the recovery does improve when the polymer concentrations are increased, it is not similar to the base case recovery. Again, this goes back to the fact that some of the oil-bank will get pushed off-pattern because the reduction in mobility will make it harder to be produced at the producer wells. Overall, in all the simulations performed in this study, the inverted 5-spot configuration still seems to out-perform the normal 5-spot configuration.

The results described in the previous paragraph highlight how injecting a polymer concentration that is slightly more than that required for a stable displacement process can help to reduce the impact of unexpected low oil-bank mobility. It was also demonstrated through fractional flow analysis and simulation how using higher polymer concentrations can help to reduce some of the sensitivity to uncertainties in the relative permeability parameters at high capillary number.

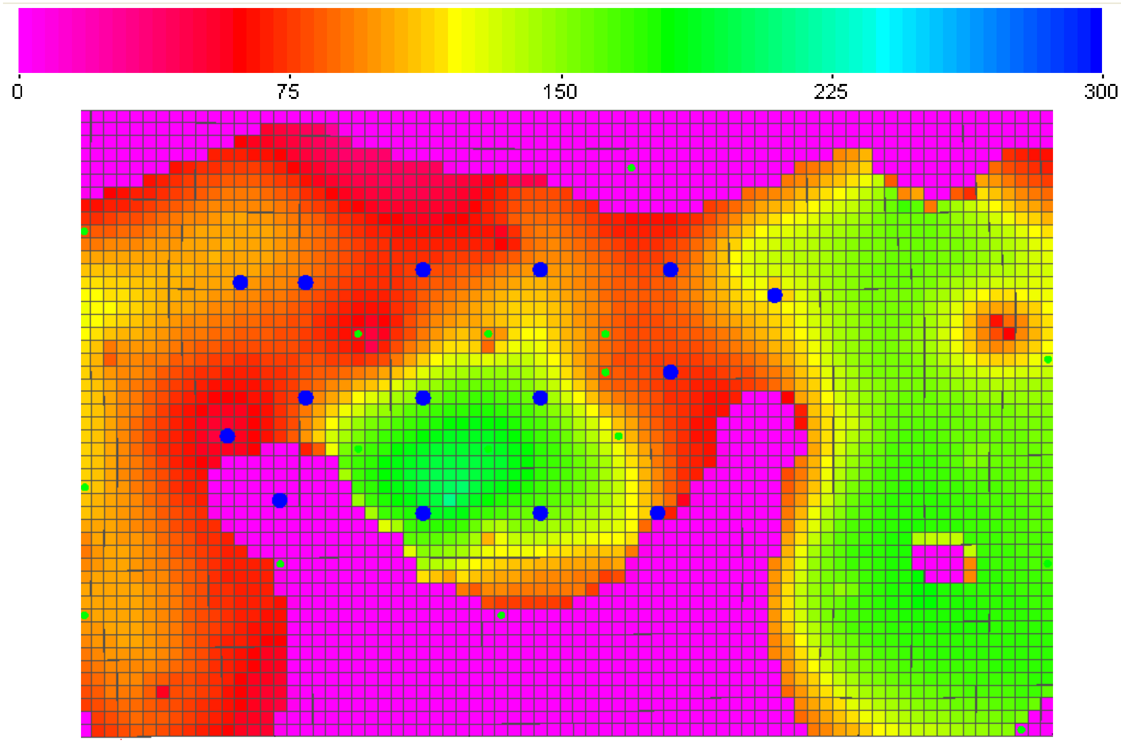

Figure 3-1: Permeability Map of Layer 1

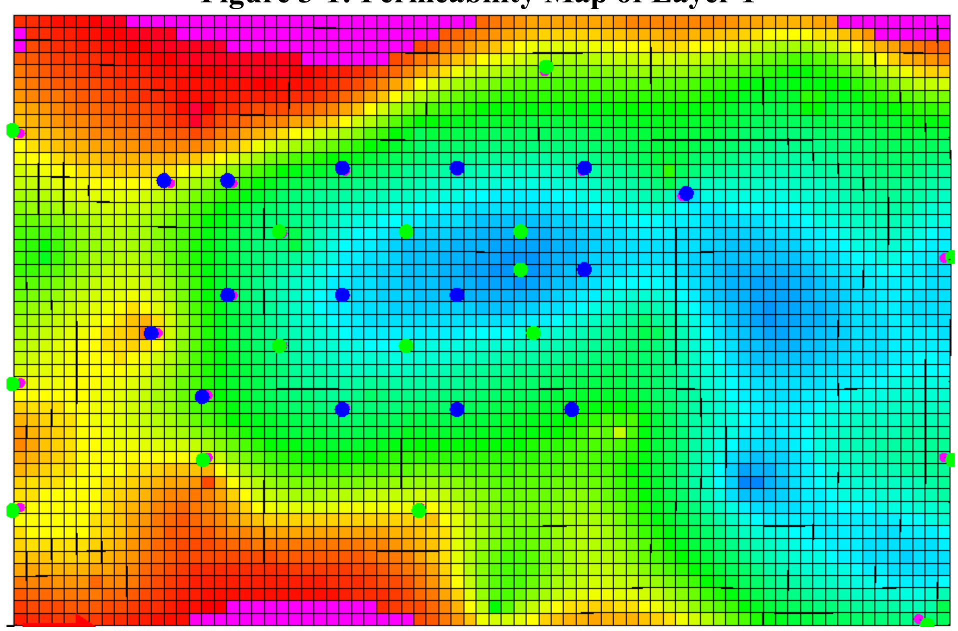

Figure 3-2: Permeability Map of Layer 9

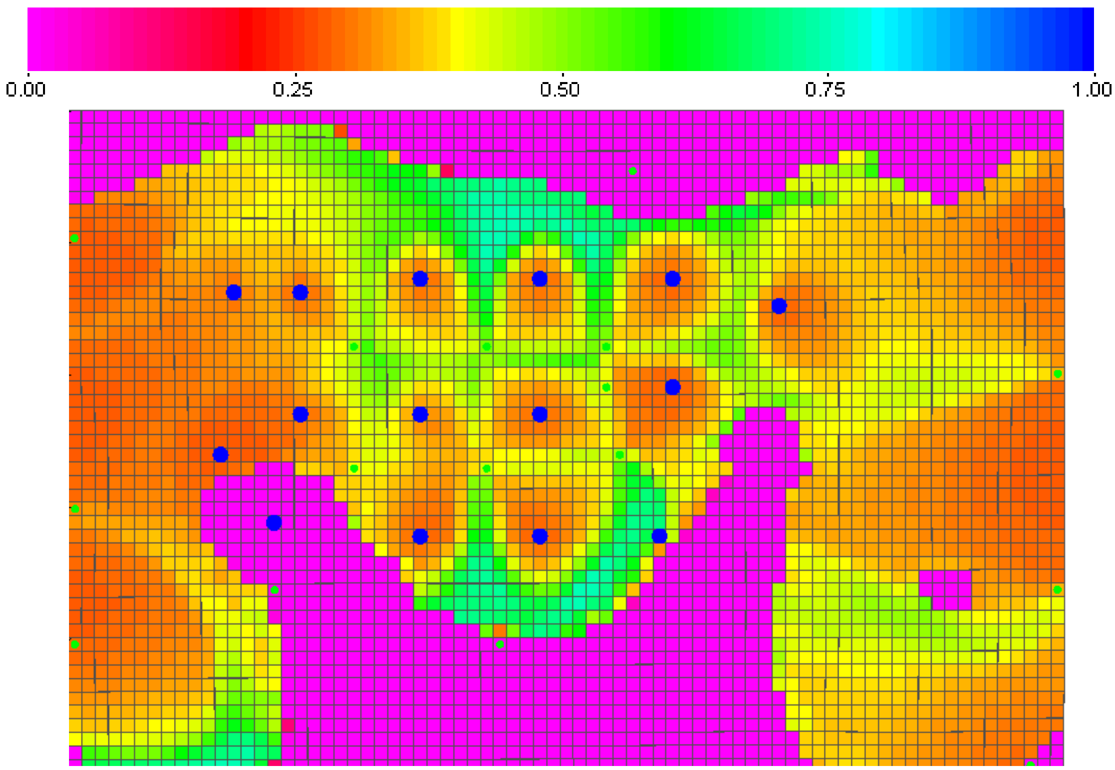

Figure 3-3: Oil Saturation Map of Layer 1

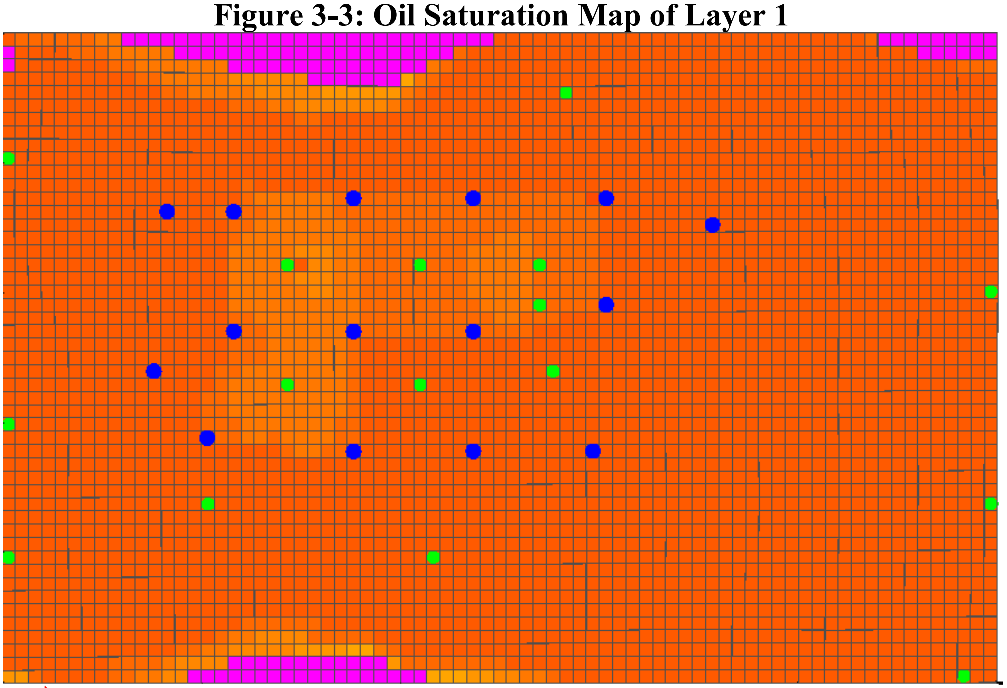

Figure 3-4: Oil Saturation Map of Layer 9

Table 3-1: Simulation Model Properties

Model Size	2625ft x 1715ft x 16.11ft
Grid size	35ft x 35t x 1.84ft (Layers 1-4) 35ft x 35ft x 1.75ft (Layers 5-9)
Average Porosity	Upper Sand - 17.6% Lower Sand - 20.1%
Average Permeability	Upper Sand - 138 md Lower Sand - 203 md
k_v/k_h	Upper Sand - 0.3 Lower Sand - 0.4
Initial Oil Saturation (before SP)	Upper Sand - 33.4% Lower Sand - 30.8%
Reservoir Depth	900 ft
Reservoir Temperature	26°C
Initial Pressure	3800 psi
Water/Oil Relative Permeability	S_{orw} = 0.282 ; S_{wrw}= 028 $k_{ro}°$ = 0.788 ; $k_{rw}°$= 0.268 e_o = 2 ; e_w= 2
Water Viscosity (at reservoir temperature)	0.93 cp
Oil Viscosity (at reservoir temperature)	11 cp
Formation Brine	Total Anion = 0.336 meq/ml Total Divalent Cation = 0.062 meq/ml
IFT	31.6 dynes/cm

Table 3-2: Surfactant and Polymer Parameters

Hand's Rule Parameters	HBNC70: 0.030 HBNC71: 0.015 HBNC72: 0.030
Optimum Salinity	0.455 meq/ml
Type III Salinity Window	CSEU: 0.370 meq/ml CSEL: 0.540 meq/ml
Surfactant Adsorption	0.25 mg/g-rock
Polymer Adsorption	20 µg/g-rock
Microemulsion Viscosity	17 cp
Trapping Number Parameters	Water = 1865 Oil = 10,000 Microemulsion = 364
Relative Permeability Parameters (at High Capillary Number)	$S_{orc} = 0.08$; $S_{orw} = 0.0$ $k_{ro}° =1$; $k_{rw}°= 1$ $e_o = 1$; $e_w = 1$

Table 3-3: Base Case SP Design

Injector Well Constraint	125 BPD
Producer Well Constraint	25 psi
Pore Volume (in Pilot Area)	345,600 bbls
Oil-in-place (in Pilot Area)	111,400 bbls
SP Slug	0.35 PV 1% Surfactant 2300 ppm polymer Salinity = 0.455 meq/ml
Polymer Drive	1 PV 2950ppm Polymer Salinity = 0.2665 meq/ml
Water Chase	Salinity = 0.1811 meq/ml

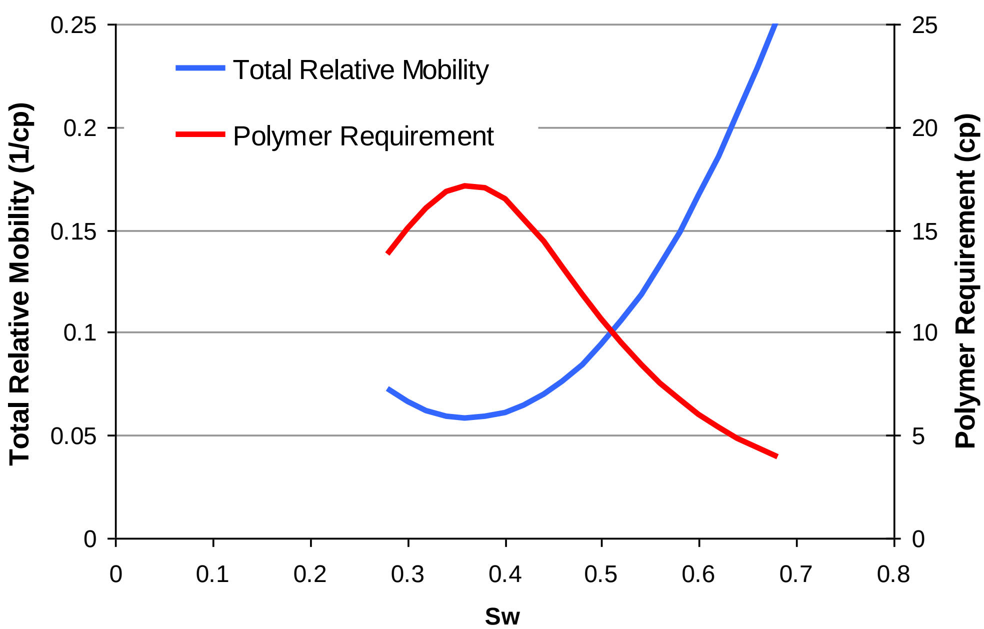

Figure 3-5: Total Relative Mobility and Corresponding Polymer Requirement

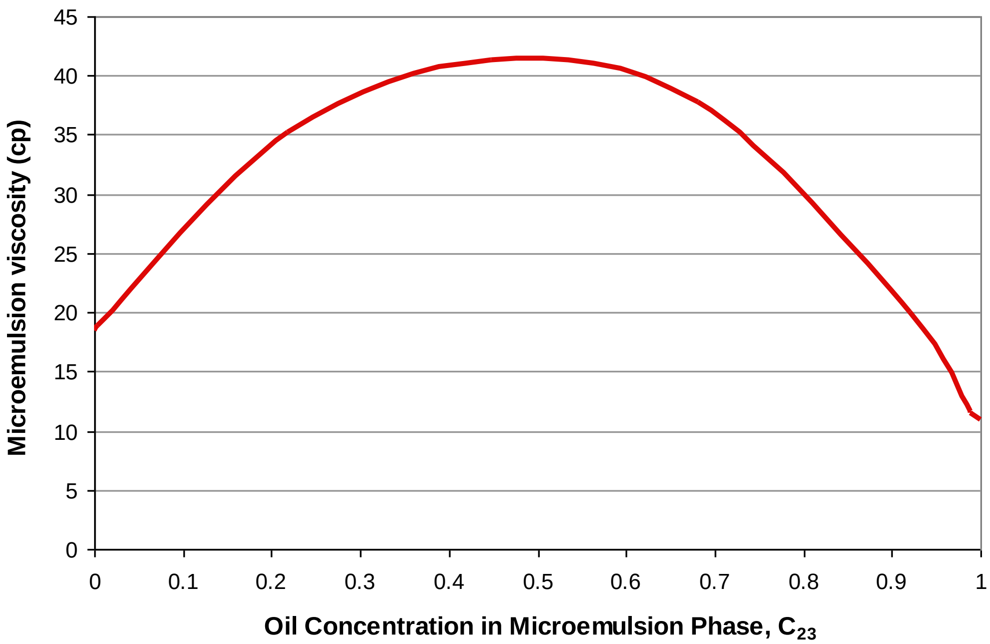

Figure 3-6: Microemulsion Viscosity

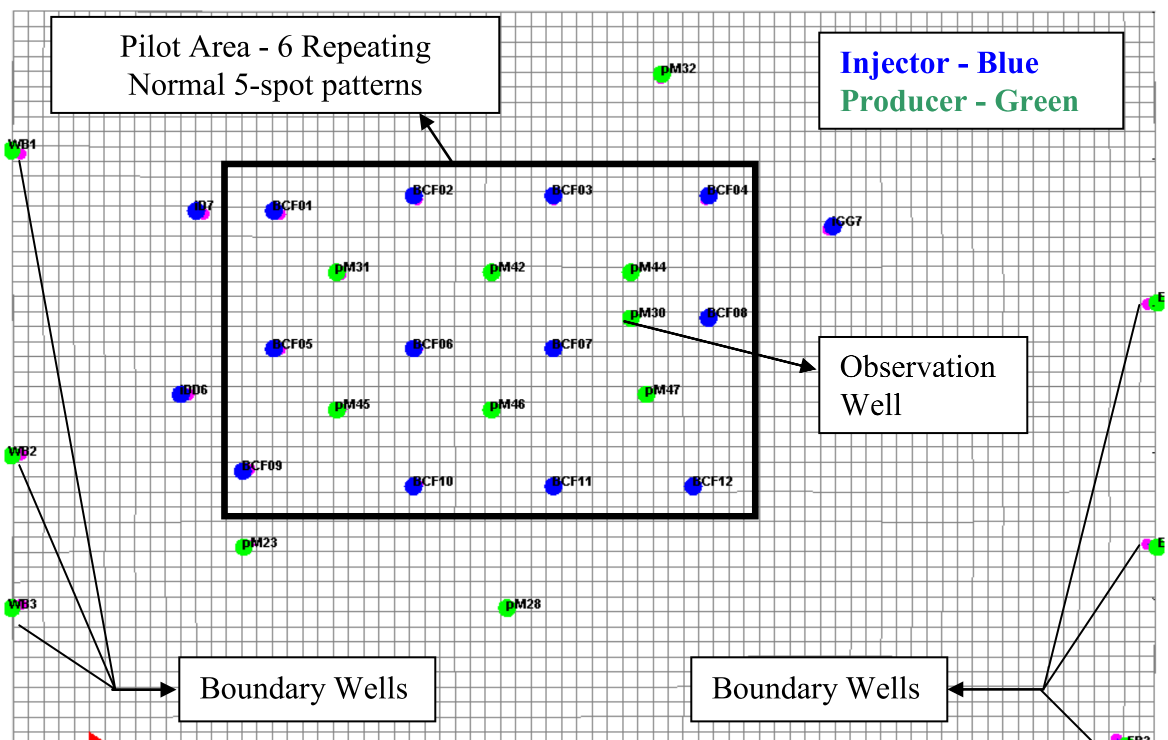

Figure 3-7: Location of Pilot Wells - Normal 5-spot Configuration

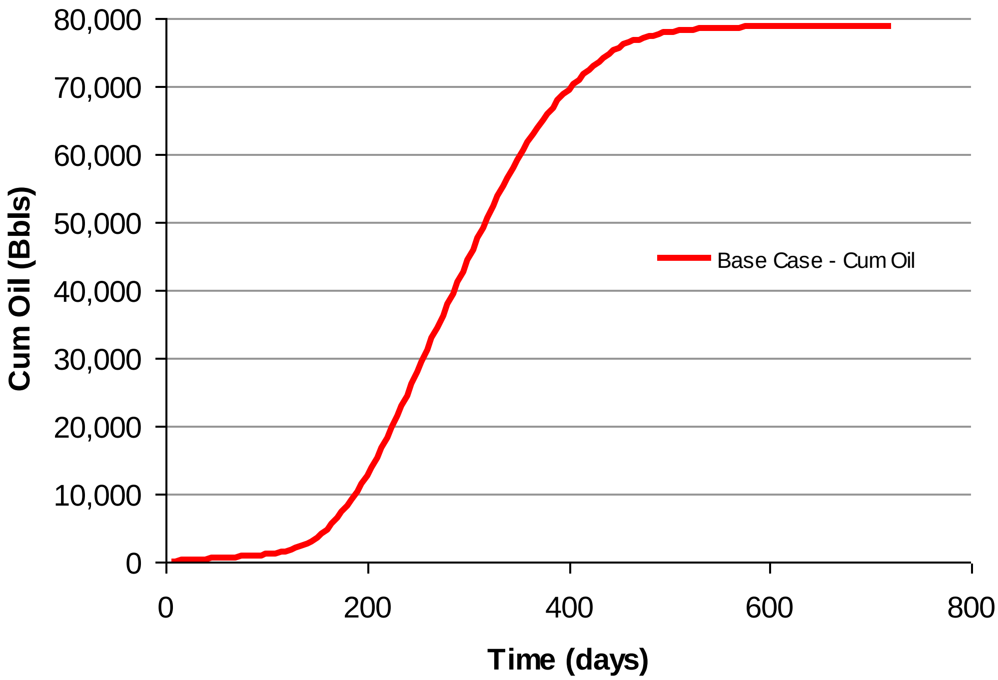

Figure 3-8: Base Case Results - Cumulative Oil Produced

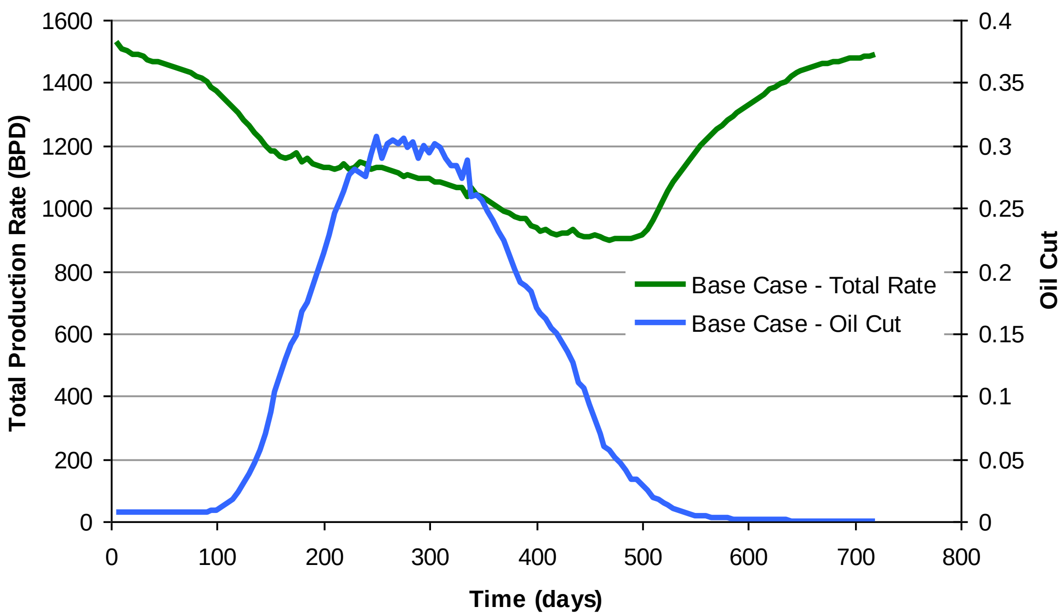

Figure 3-9: Base Case Results - Total Production Rate and Oil Cut

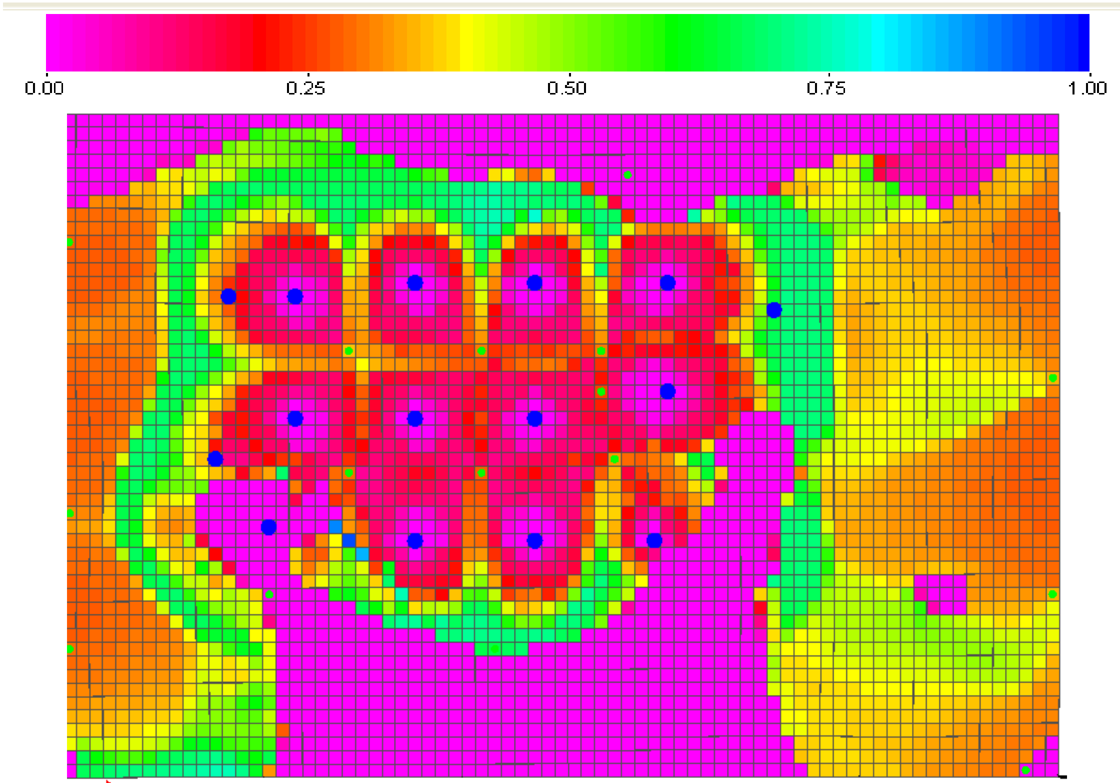

Figure 3-10: Base Case - Oil Saturation after Water Chase (Layer 1)

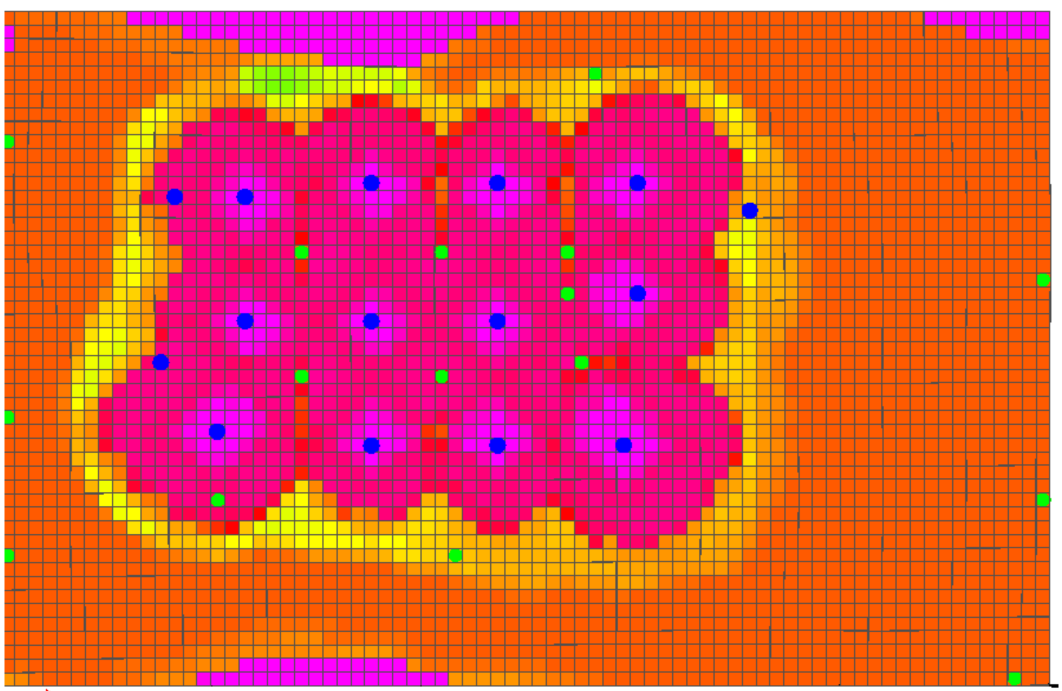

Figure 3-11: Base Case - Oil Saturation after Water Chase (Layer 9)

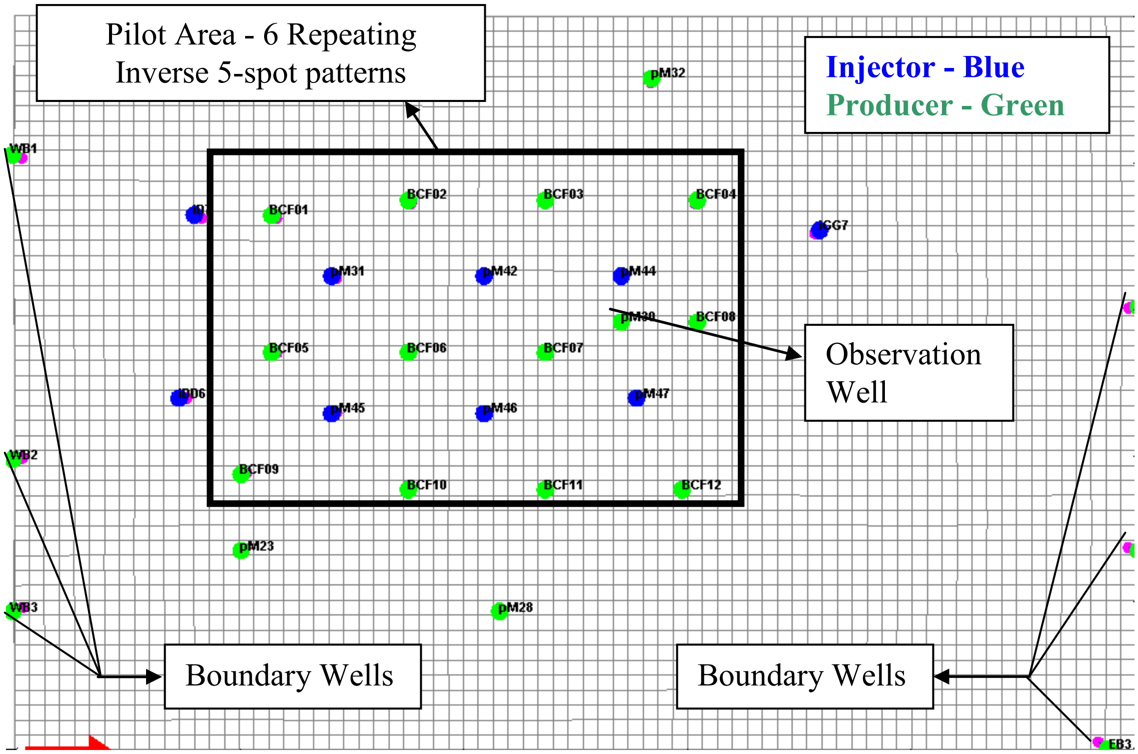

Figure 3-12: Location of Pilot Wells - Inverse 5-spot Configuration

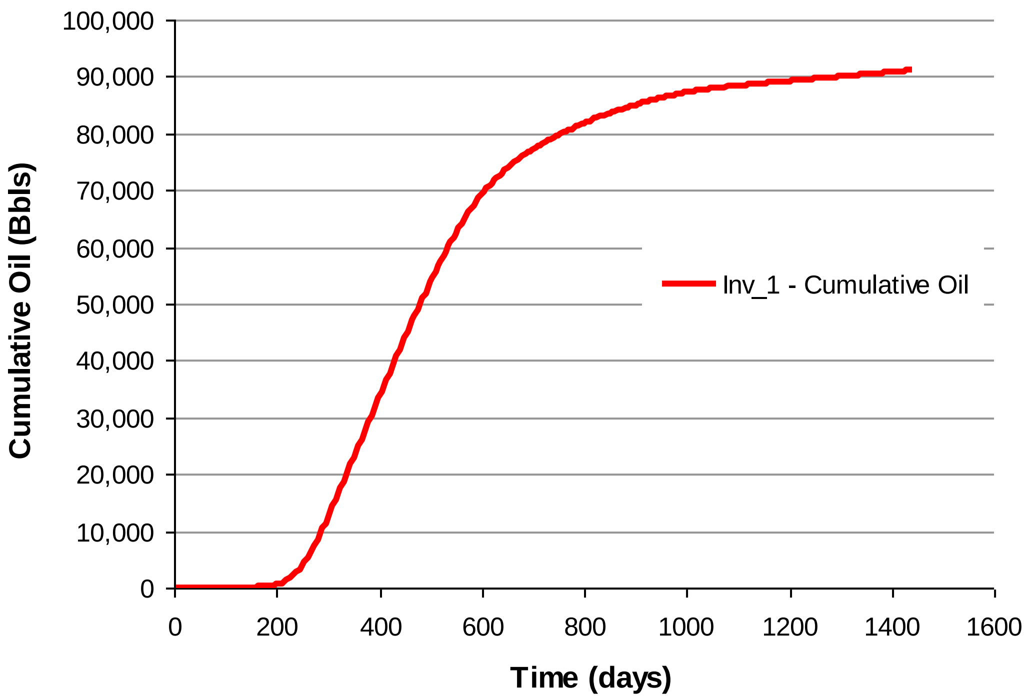

Figure 3-13: Inverted 5-spot Configuration - Cumulative Oil Recovered

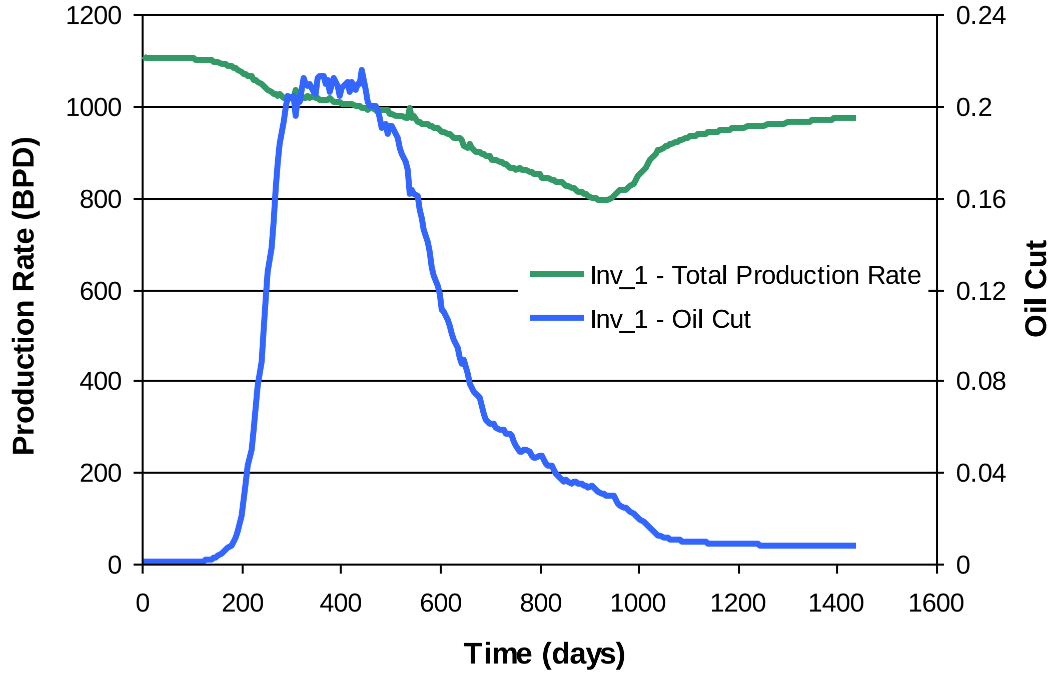

Figure 3-14: Inverted 5-spot Comparison - Total Production Rate and Oil Cut

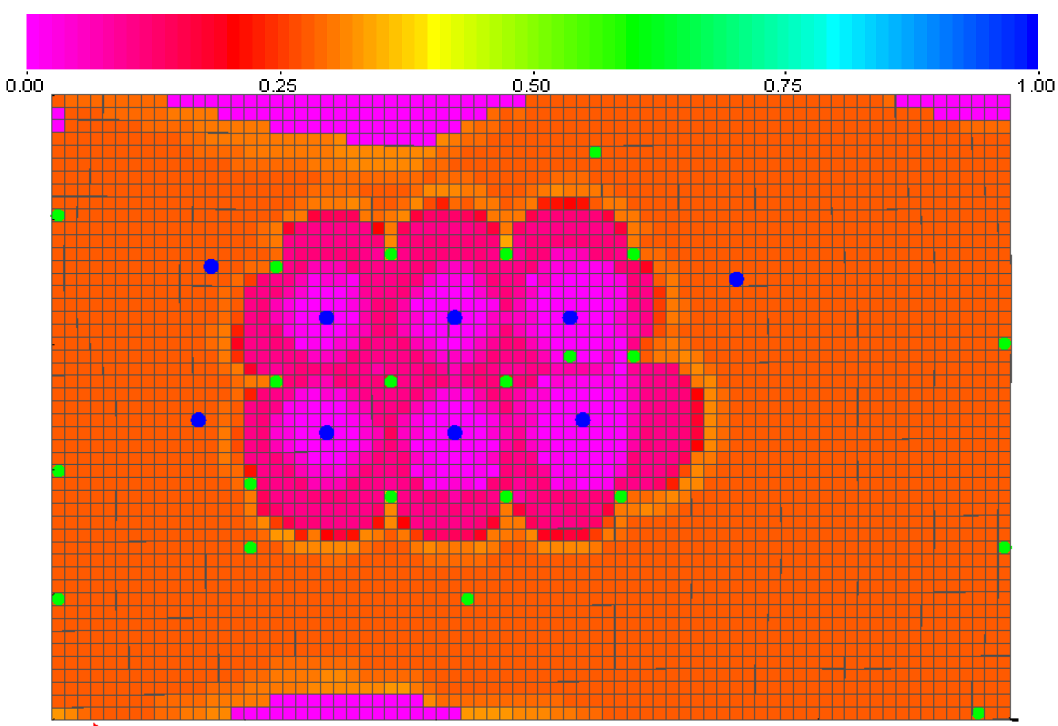

Figure 3-15: Inverted 5-spot - Oil Saturation after Water Chase (Layer 9)

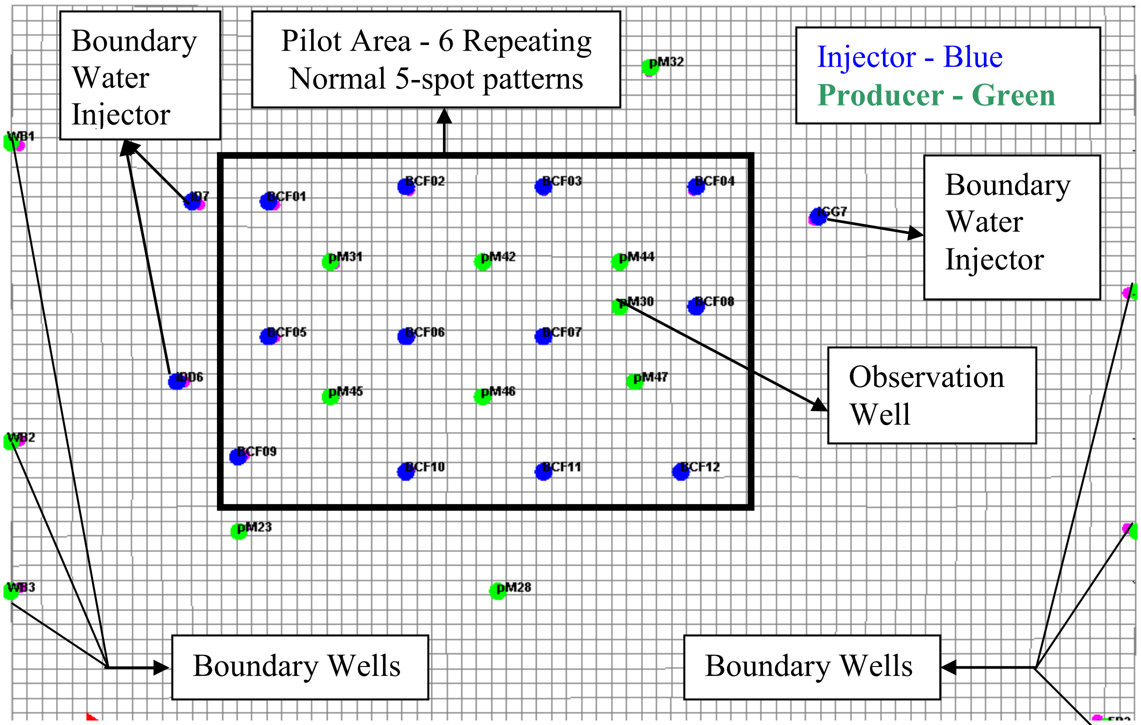

Figure 3-16: Normal 5-spot configuration with boundary water injectors

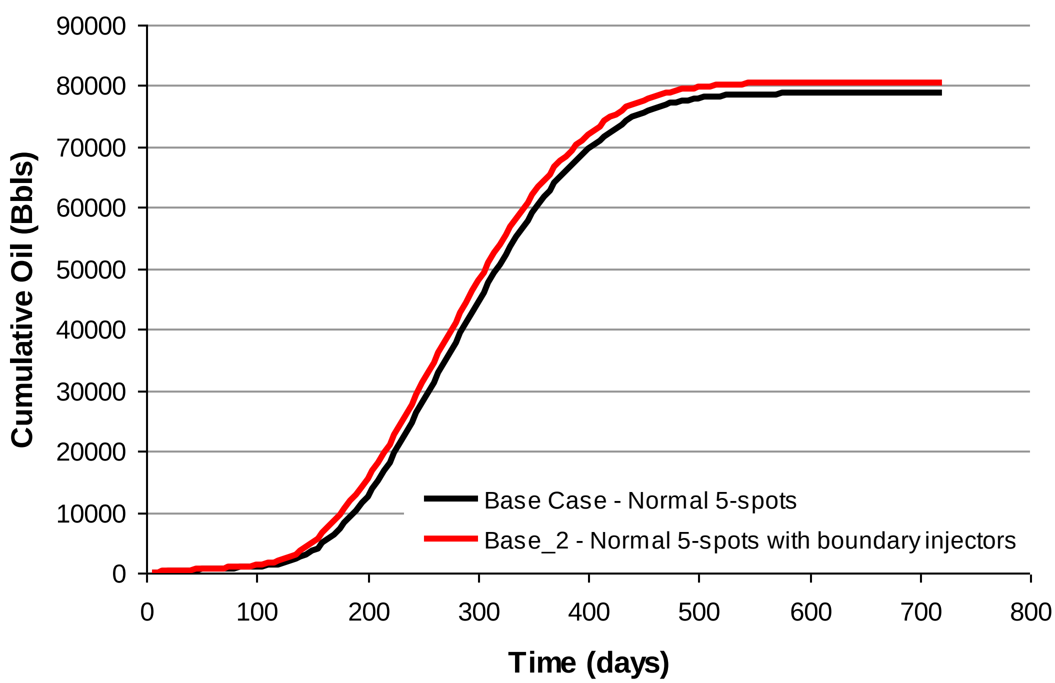

Figure 3-17: Normal 5-spot with boundary injectors - Cumulative Oil Comparison

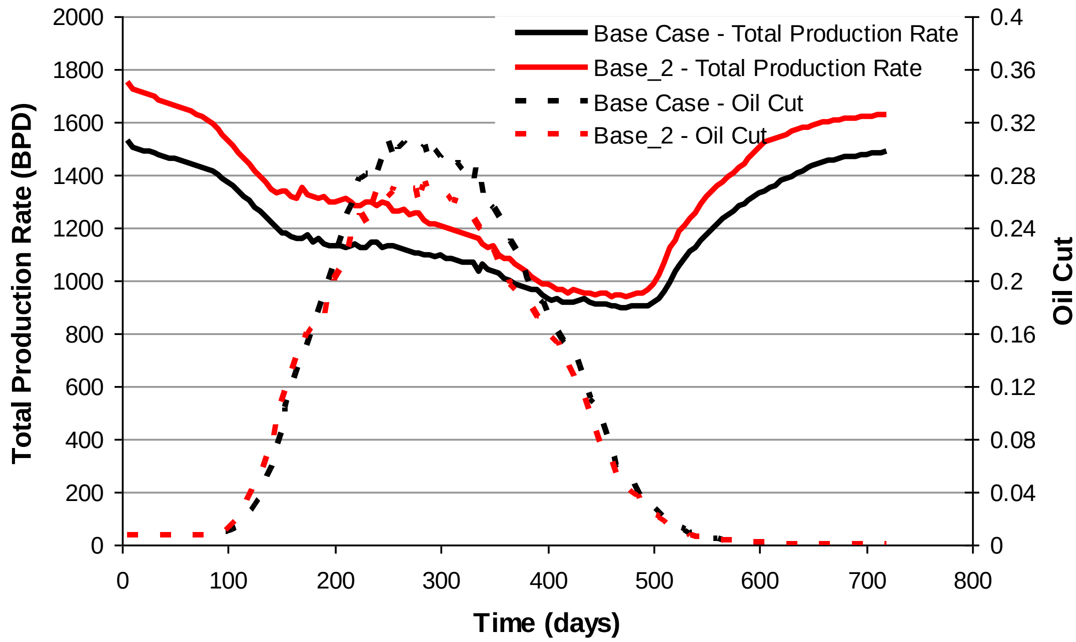

Figure 3-18: Normal 5-spot with boundary injectors - Production Rate and Oil Cut

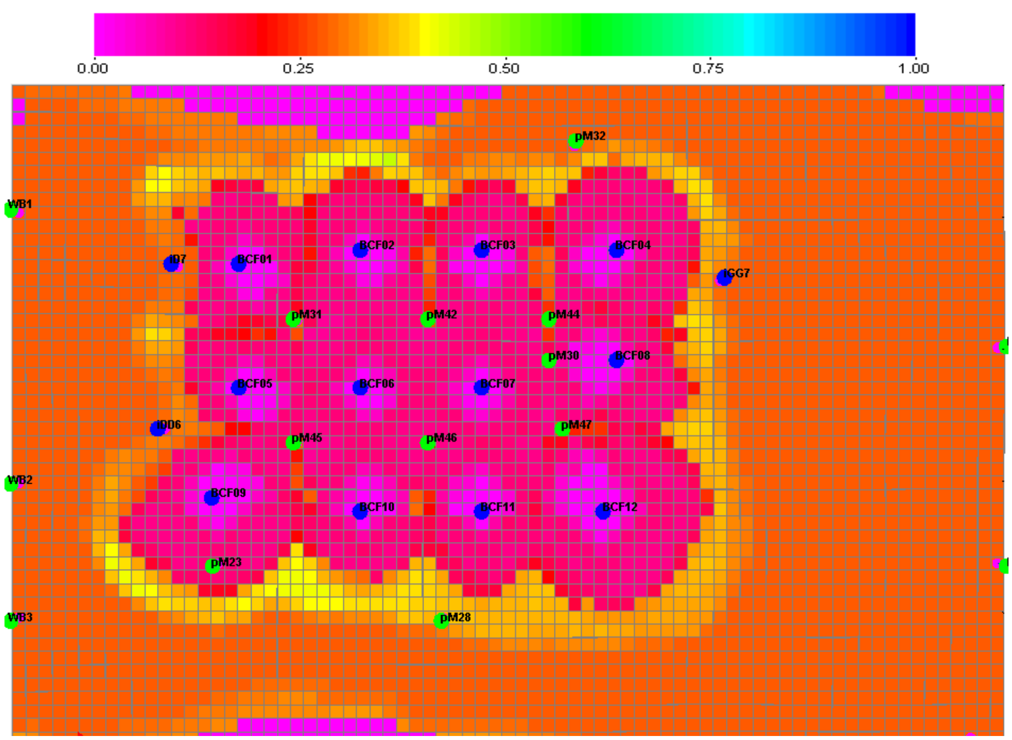

Figure 3-19: Normal 5-spot with boundary injectors - Oil Saturation after Water Chase (Layer 9)

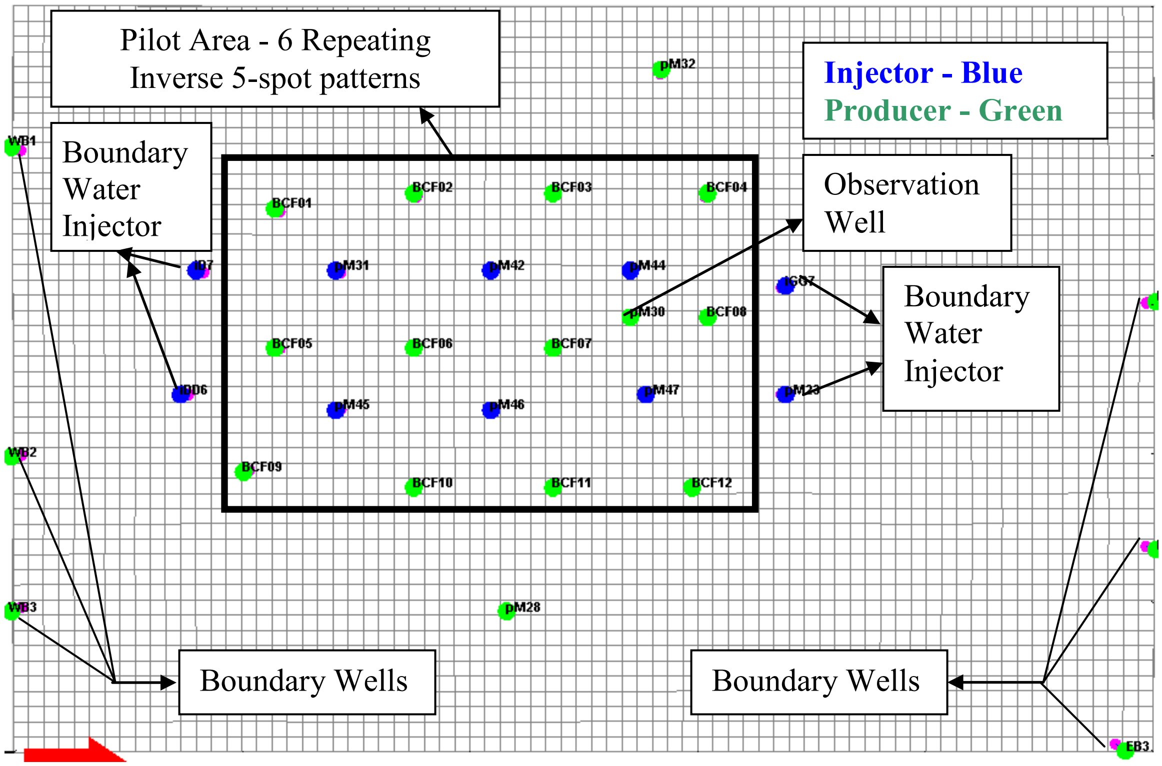

Figure 3-20: Inverted 5-spot pattern with boundary injectors

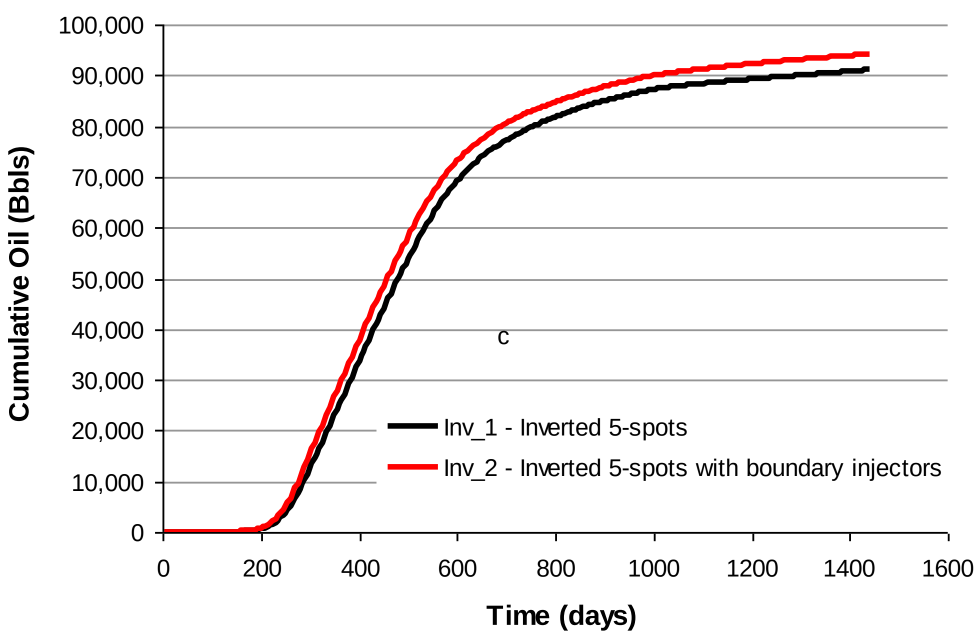

Figure 3-21: Inverse 5-spot with boundary wells - Cumulative Oil Comparison

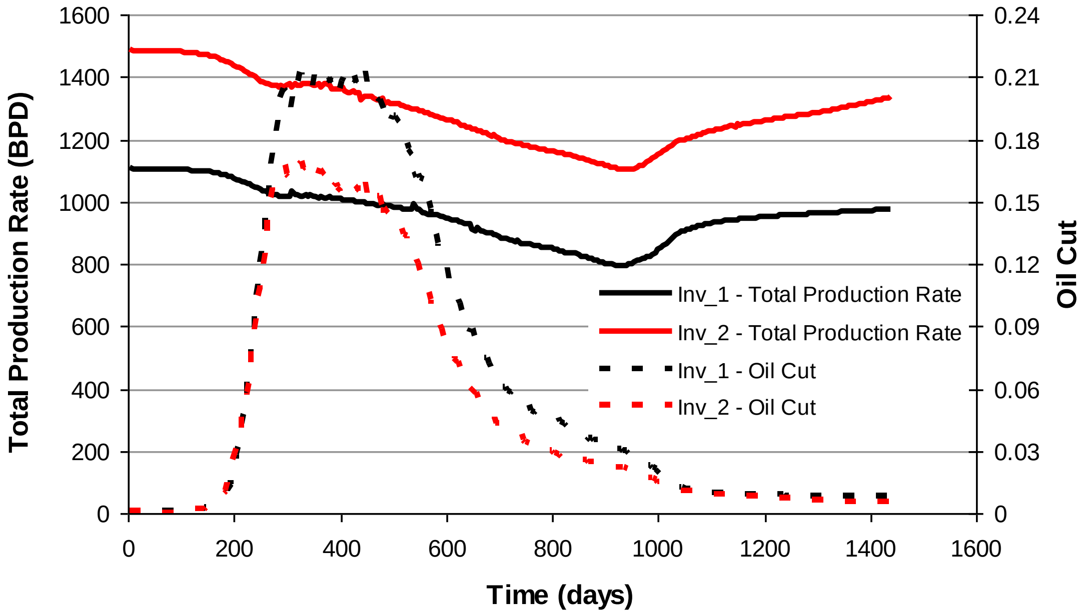

Figure 3-22: Inverse 5-spot with boundary wells - Production Rate and Oil Cut

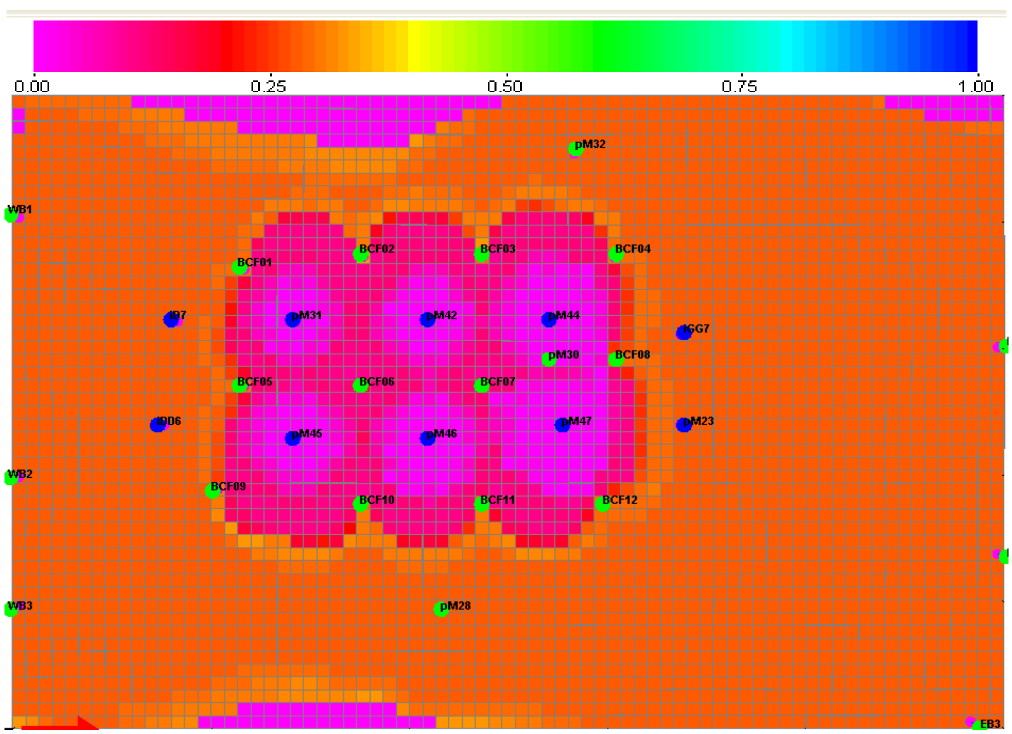

Figure 3-23: Inverse 5-spot with boundary wells - Oil Saturation after Water Chase (Layer 9)

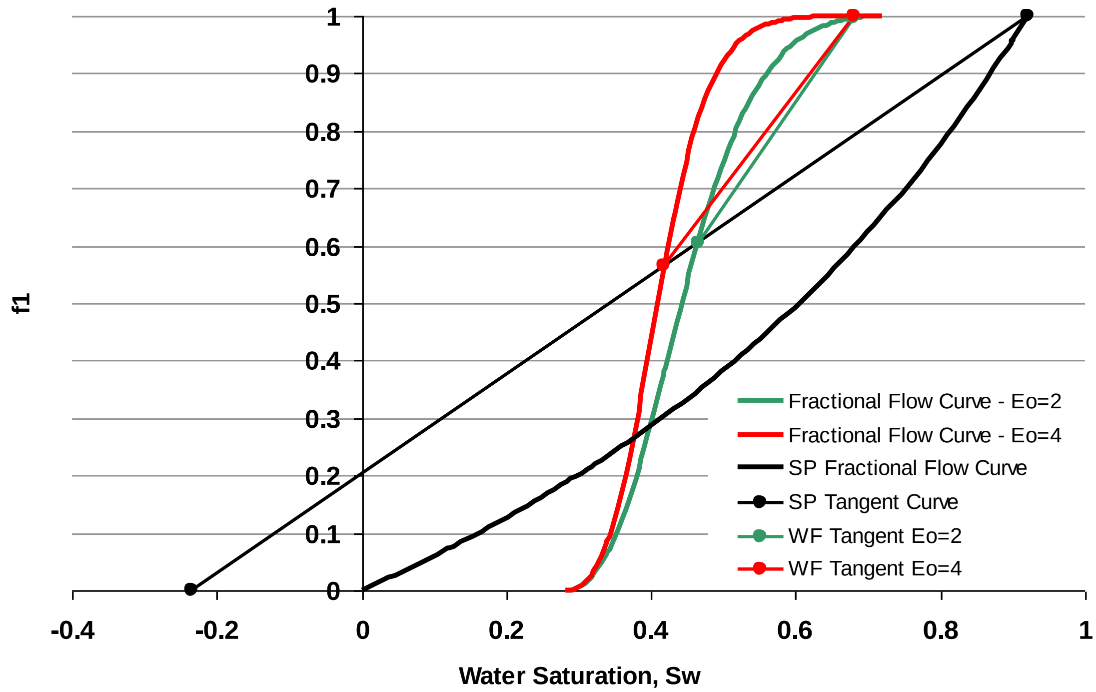

Figure 3-24: Fractional Flow Curves - Effect of Increasing Oil Exponent

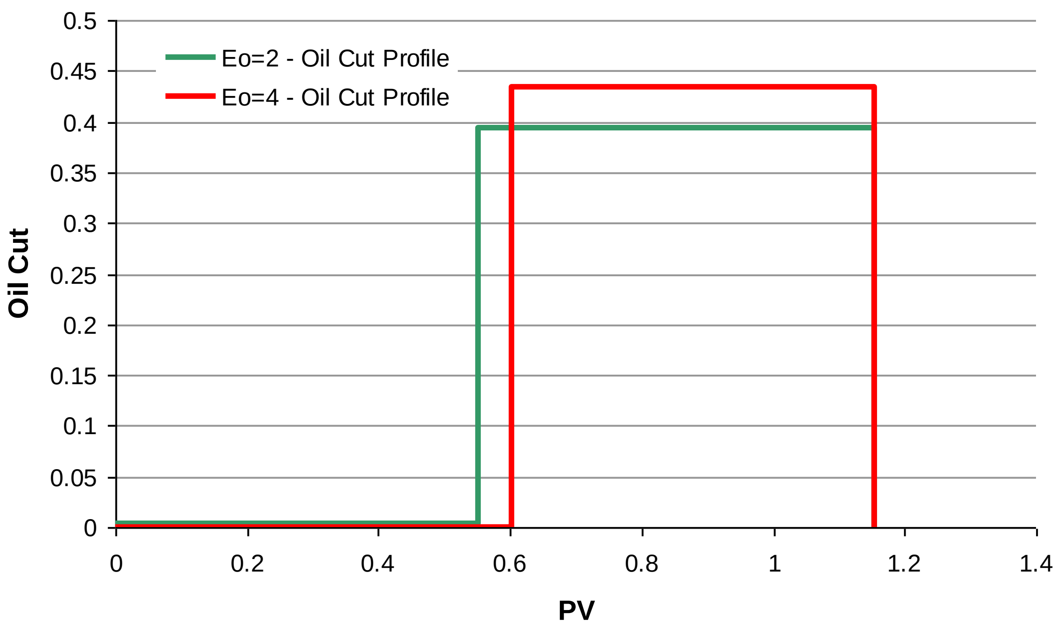

Figure 3-25: Oil Cut Profile - Effect of Increasing Oil Exponent

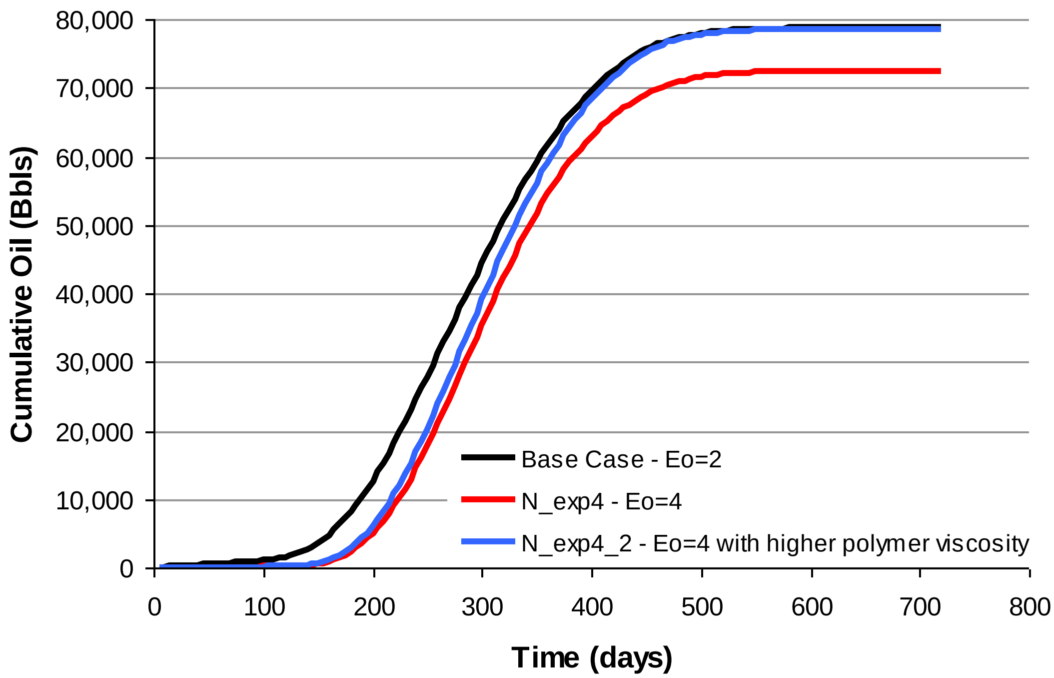

Figure 3-26: Normal 5-spot - Cumulative Oil (Eo=2 vs. Eo=4)

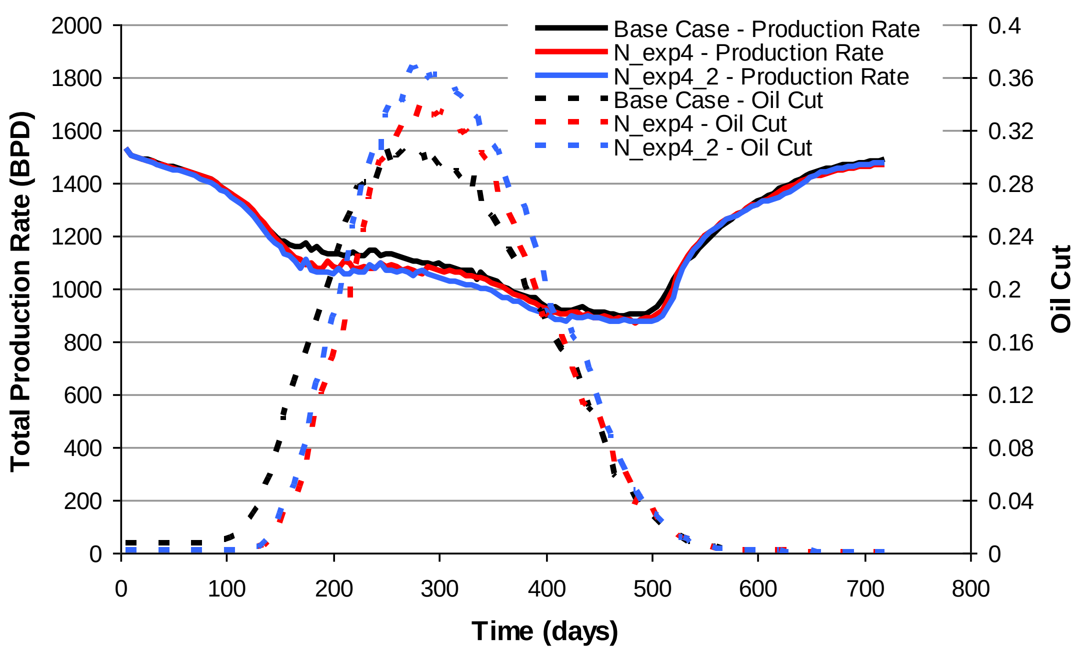

Figure 3-27: Normal 5-spot - Effect of Increasing Oil Exponent - Total Production Rate and Oil Cut

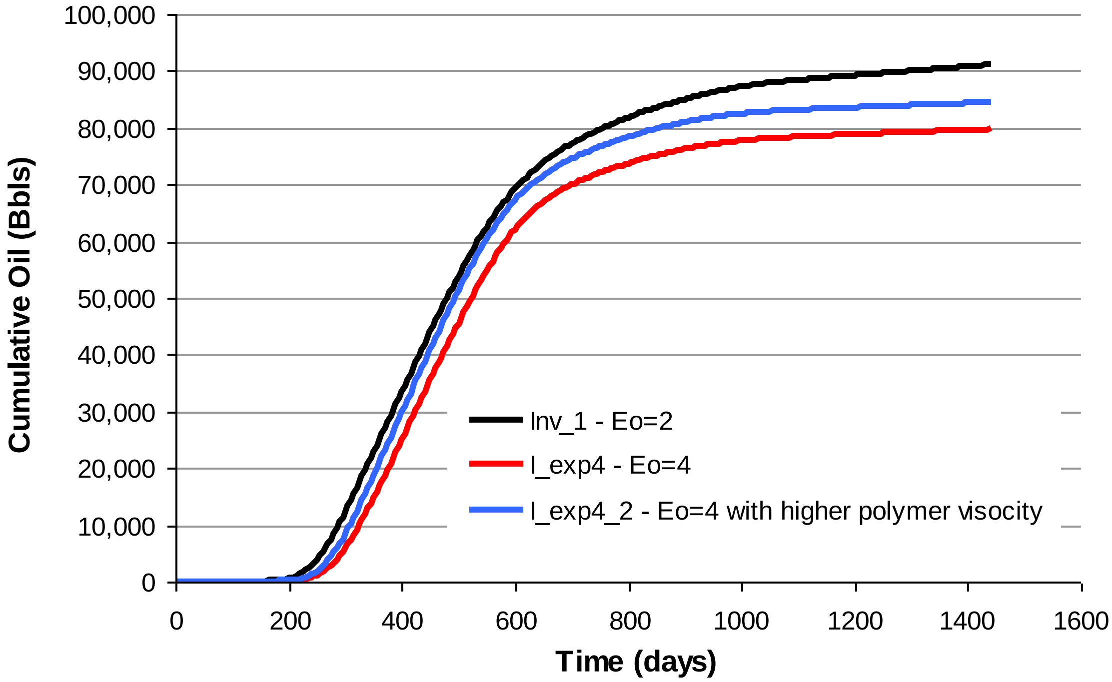

Figure 3-28: Inverted 5-spot - Effect of Increasing Oil Exponent - Cumulative Oil

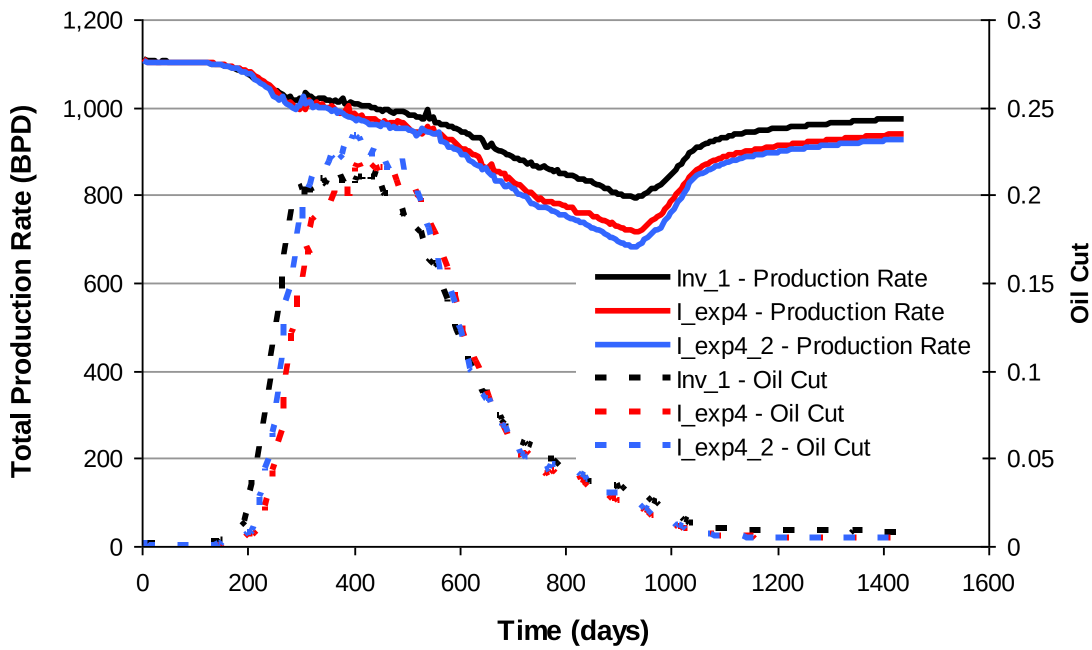

Figure 3-29: Inverted 5-spot - Effect of Increasing Oil Exponent - Total Production Rate and Oil Cut

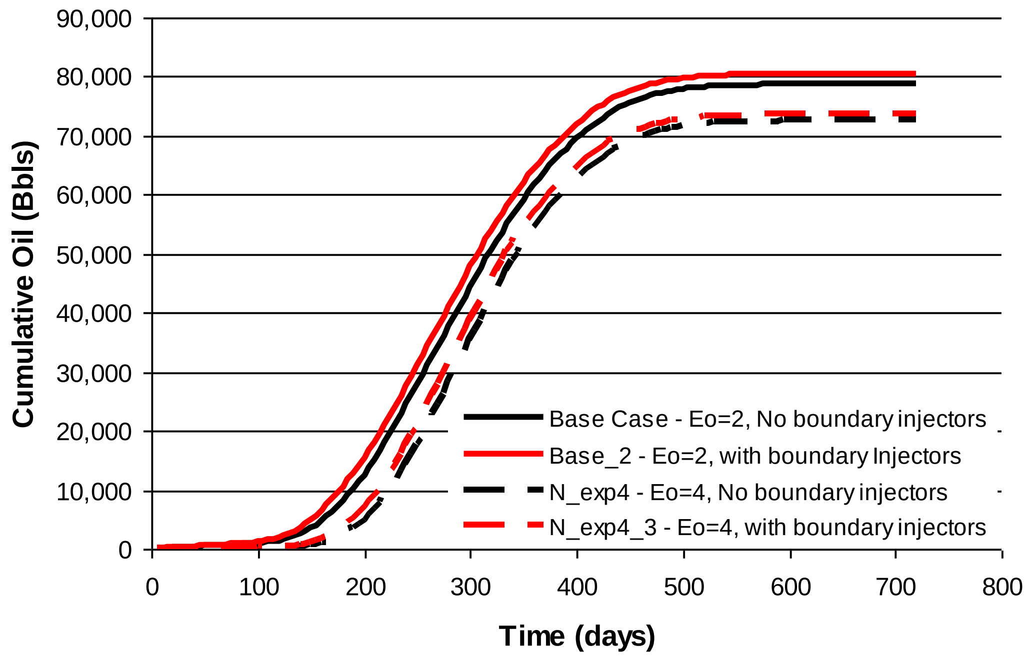

Figure 3-30: Normal 5-spot configurations - Effect of Increasing the Oil Exponent on the Cumulative Recovery

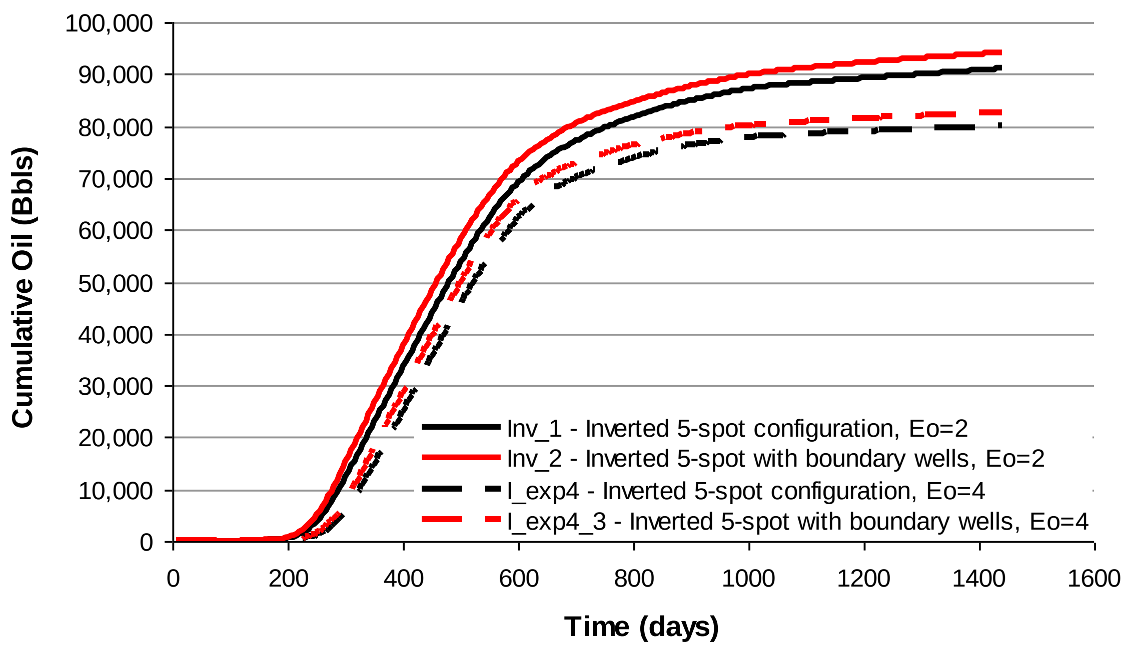

Figure 3-31: Inverted 5-spot configurations - Effect of Increasing the Oil Exponent on the Cumulative Recovery

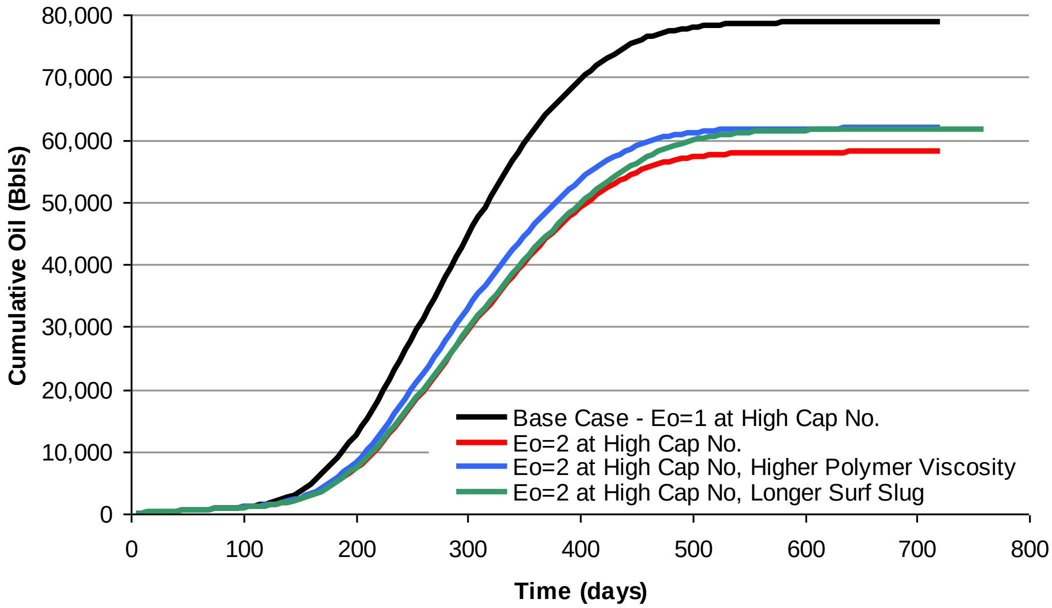

Figure 3-32: Normal 5-spot - Effect of Increasing Oil Exponent at High Capillary Number

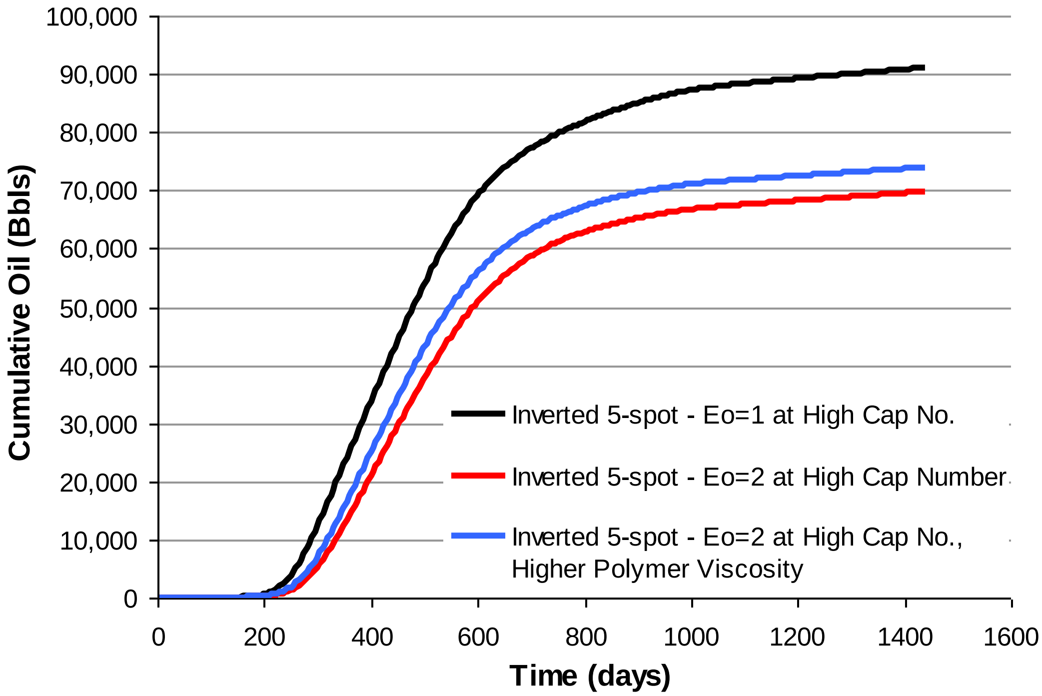

Figure 3-33: Inverted 5-spot - Effect of Increasing the Oil Exponent at High Capillary Number

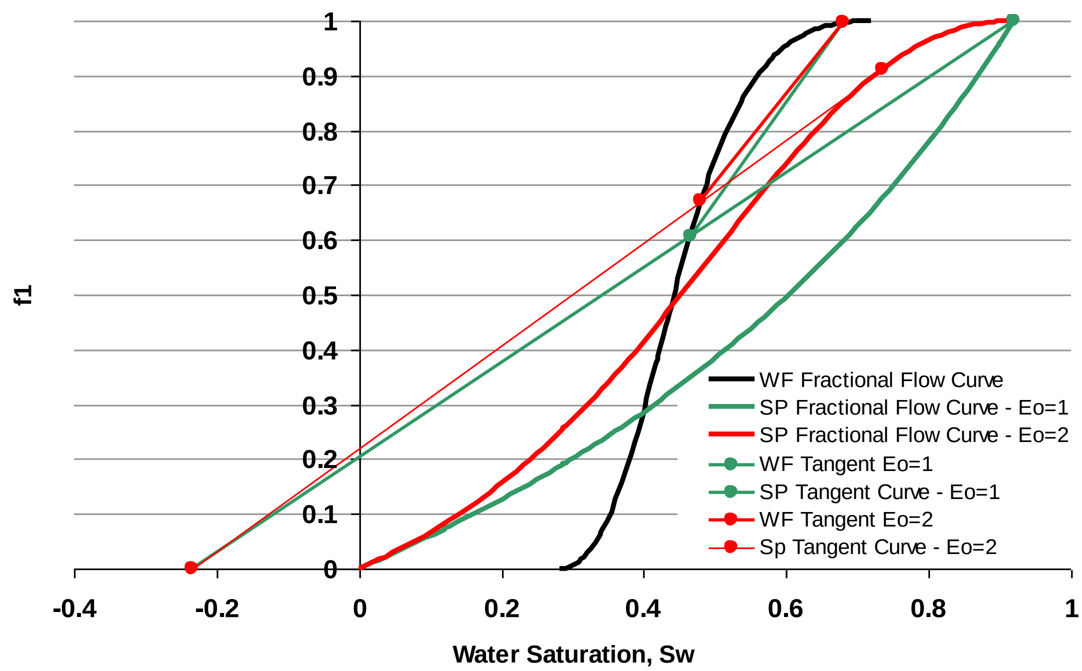

Figure 3-34: Fractional Flow Curves - Impact of Increasing the Oil Exponent at High Capillary Number

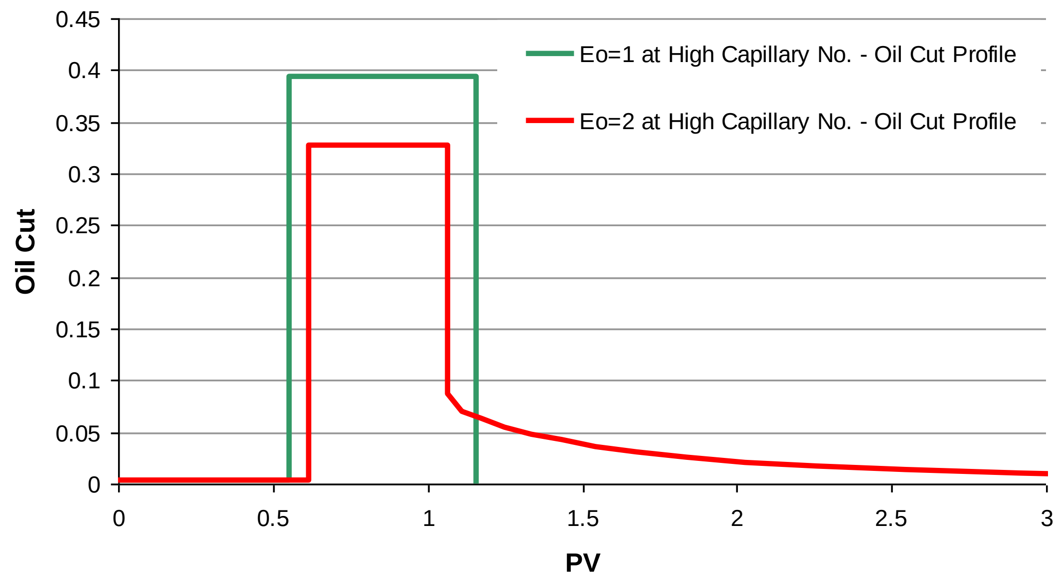

Figure 3-35: Oil Cut Profile - Impact of Increasing the Oil Exponent at High Capillary Number

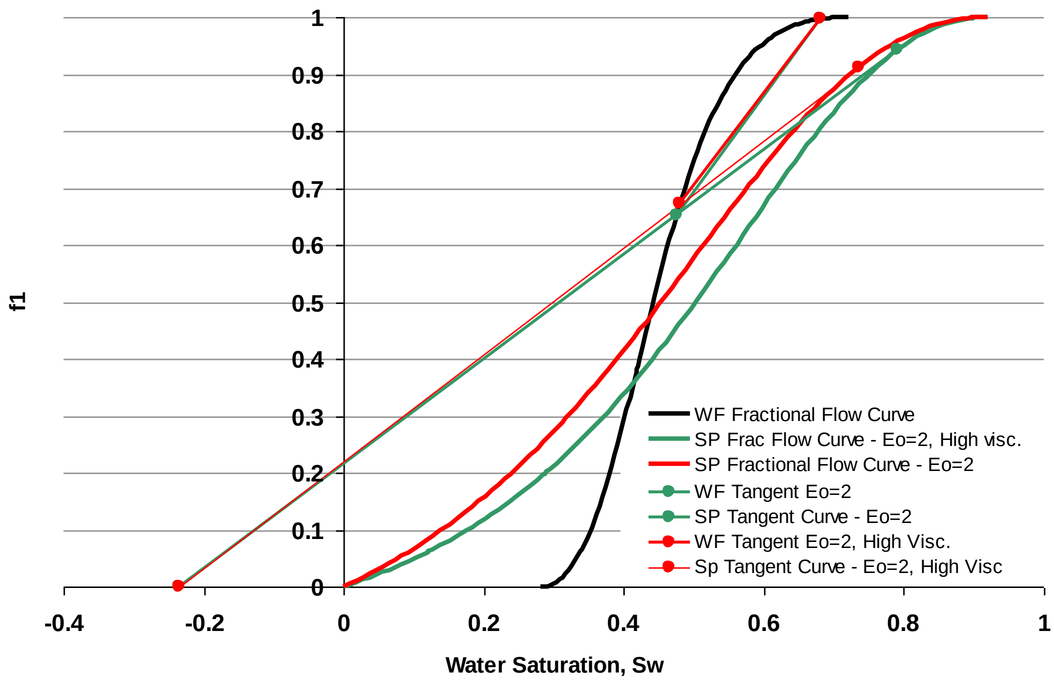

Figure 3-36: Fractional Flow Curve - Impact of Increasing Polymer Viscosity in SP slug

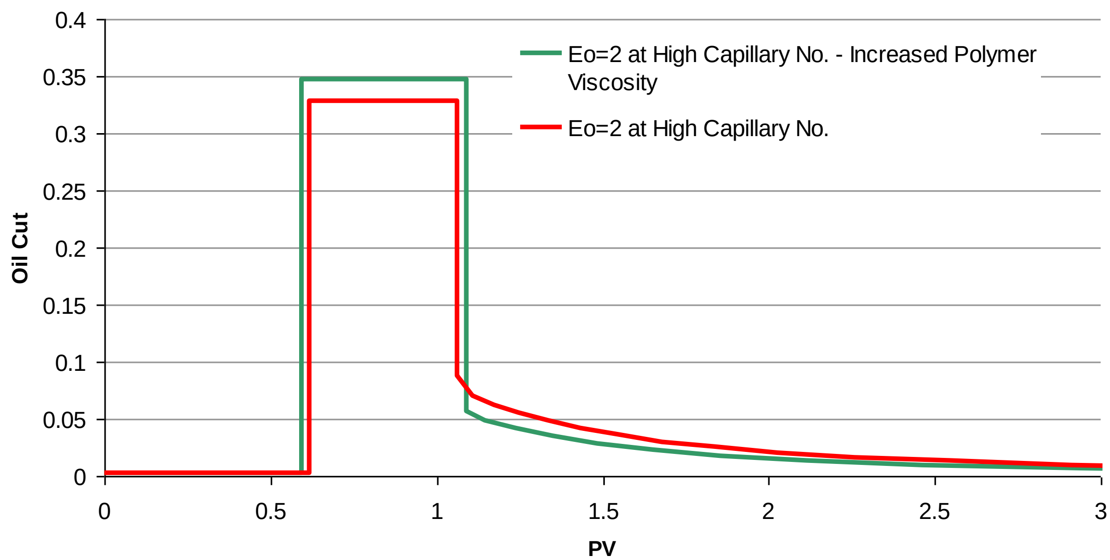

Figure 3-37: Oil Cut Profile - Impact of Increasing Polymer Viscosity in SP Slug

Table 3-4: Description of Simulations Performed in this Chapter

Simulation Name	Description	Surfactant Slug Size (PV)	Surfactant Conc. (vol%)	Polymer Drive Size (PV)	Polymer Concentration (wt%)		Cumulative Oil (bbls)
					in SP	in PD	
Base Case	Normal 5-spot configuration	0.35	1	1	0.230	0.295	78,834
Inv_1	inverted 5-spot configuration	0.35	1	1	0.230	0.295	91,111
Base_2	Normal 5-spot configuration with boundary injectors	0.35	1	1	0.230	0.295	80,613
Inv_2	Inverted 5-spot configuration with boundary injectors	0.35	1	1	0.230	0.295	94,162
N_exp4	Normal 5-spot configuration. Oil exponent = 4 at Low Capillary Number	0.35	1	1	0.230	0.295	72,549
N_exp4_2	Normal 5-spot configuration. Oil exponent = 4 at Low Cap. No. Increased polymer concentration	0.35	1	1	0.265	0.323	78,625
I_exp4	inverted 5-spot configuration. Oil exponent = 4 at Low Cap. No.	0.35	1	1	0.230	0.295	79,766
I_exp4_2	inverted 5-spot configuration. Oil exponent = 4 at Low Cap No. Increased polymer concentration	0.35	1	1	0.265	0.323	84,519
N_exp4_3	Normal 5-spot configuration with boundary injectors. Oil exponent = 4 at Low Cap. No.	0.35	1	1	0.230	0.295	73,594
I_exp4_3	inverted 5-spot configuration with boundary injectors. Oil exponent = 4 at Low Cap. No.	0.35	1	1	0.230	0.295	82,437
N_ehc_1	Normal 5-spot configuration. Oil exponent = 2 at high capillary number	0.35	1	1	0.230	0.295	57,987
N_ehc_2	Normal 5-spot configuration. Oil exponent = 2 at High Cap. No. Increased polymer concentration	0.35	1	1	0.265	0.323	61,771
N_ehc_3	Normal 5-spot configuration. Oil exponent = 2 at High Cap. No. Increased surfactant slug size. Same PVxC	0.47	0.75	1	0.230	0.295	61,571
I_ehc_1	Inverted 5-spot configuration. Oil exponent = 2 at High Cap. No.	0.35	1	1	0.230	0.295	69,813
I_ehc_2	Inverted 5-spot configuration. Oil exponent = 2 at High Cap. No. Increased polymer concentration	0.35	1	1	0.265	0.323	73,980

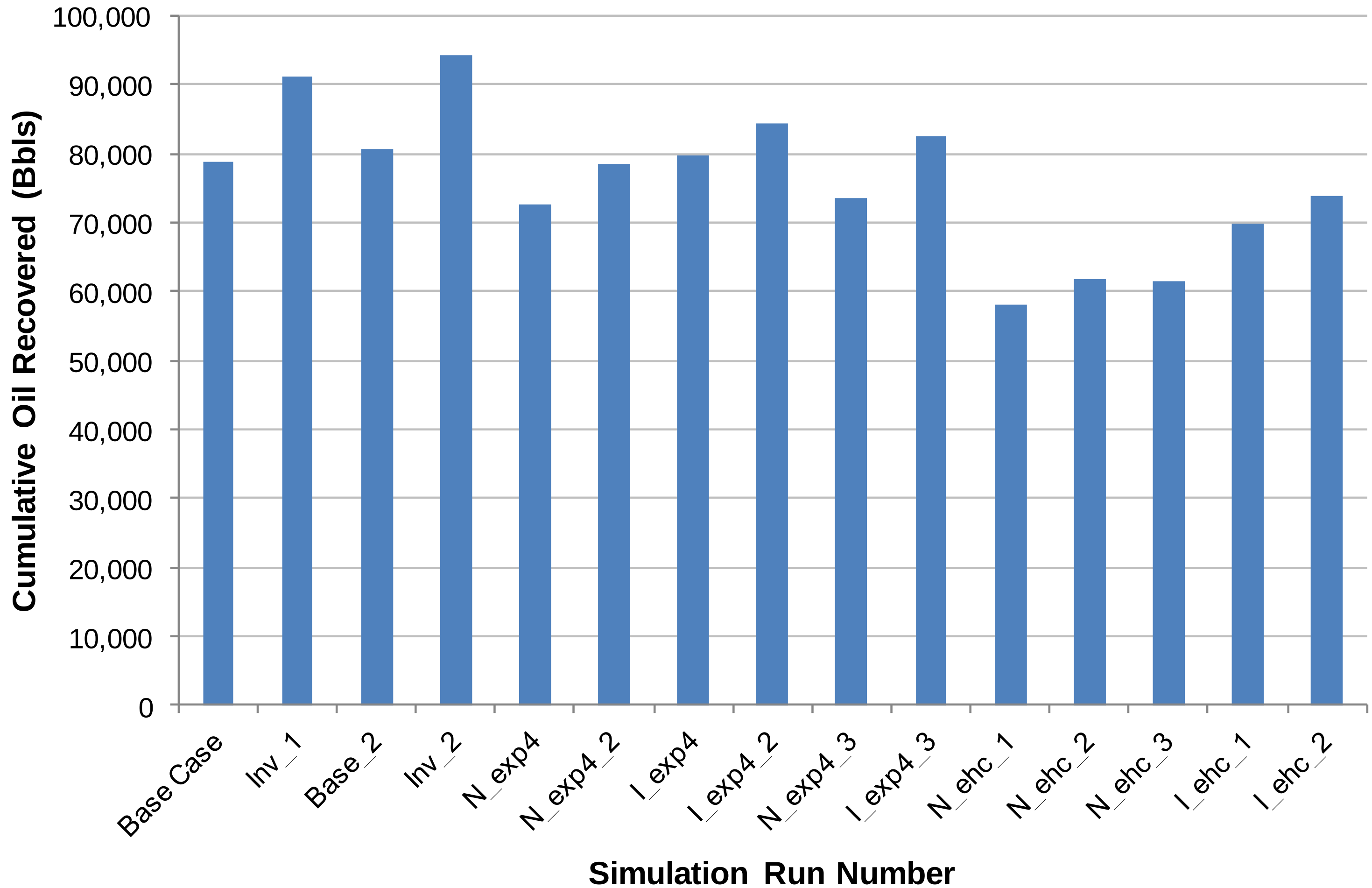

Figure 3-38: Comparison of Cumulative Oil Recovered for the Simulations Performed in this Chapter

CHAPTER 4 : CHEMICAL FLOOD DESIGN IN A HETEROGENEOUS, LOW-PERMEABILITY RESERVOIR WITH HORIZONTAL WELLS

This chapter will focus on investigating the impact of simulation grid refinement and other select parameters on the oil recovery of a heterogeneous, low-permeability, high temperature carbonate reservoir. Because of the low permeability of this reservoir, the loss in injectivity from the polymer will result in a slow breakthrough of the oil-bank. As a result, unstable Surfactant and SP floods were also investigated as a recovery option using a fine-scale simulation grid.

4.1 SIMULATION MODEL

The reservoir is approximately 6000ft deep and 12ft thick, and contains mostly dolomite with average permeability and porosity of 3md and 12.5% respectively. The reservoir is currently in the secondary stage of development, with the current average oil saturation at 46% and average oil cut of approximately 14%.

The original model is a 39,600ft x 4,150ft x 12ft grid with x-direction gridblock size of 200ft and y-direction gridblock size of 50ft. In the z-direction, the first two layers are 2.04ft thick and the bottom two layers are 4.12ft thick. The first two layers are referred to as 'Rock Type 1' and contain different petrophysical properties from the bottom two layers, which is referred to as 'Rock Type 2'. The variable permeability, porosity, water saturation, initial pressure and depth were provided by the operator after calibrating their simulation model by history matching the field data. A map of the permeability field in the first layer of the simulation model is shown in Figure 4-2. More field properties are summarized in Table 4-1 and Table 4-2

Information regarding the completions of the deviated wells was provided by the operator. Additionally, transmissibility modifiers were used for each well-block completion rather the calculated value of the productivity index. In UTCHEM, the constant part of the productivity index for a horizontal well is calculated by the formula:

$$PI_{constant} = \frac{2\pi\sqrt{k_y k_z}\Delta x}{(0.15802)\left(\ln\left[\frac{r_o}{r_w}\right]+S\right)} \qquad 4.1$$

Where,

k_y = y-direction permeability

k_z = z-direction permeability

Δx = Gridblock thickness in x-direction

r_o = Equivalent radius

r_w = Wellbore radius

S = Skin factor

The equivalent radius is calculated using Peaceman's model

$$r_o = 0.28\left(\frac{\left(\left(\frac{k_y}{k_z}\right)^{1/2}\Delta z^2+\left(\frac{k_z}{k_y}\right)^{1/2}\Delta y^2\right)^{1/2}}{\left(\frac{k_y}{k_z}\right)^{1/4}+\left(\frac{k_z}{k_y}\right)^{1/4}}\right) \qquad 4.2$$

Where,

Δz = Gridblock thickness in z-direction

Δy = Gridblock thickness in y-direction

The use of transmissibility modifiers in place of the calculation described above will simplify the procedure to correct for injectivity based on grid size (more details about this procedure are provided in the next section). However, this option should be used with caution and since it is very easy to find a set of transmissibility modifiers that can match the field data while misrepresenting the field geology at the same time. In this case study, the transmissibility modifiers were provided by the operator after matching their field production during waterflood.

4.2 Refinement Procedure

Three simulation grids were constructed by copying the gridblock properties of the base case grid. The pilot area consisted of a small part of the entire grid model and so it was decided that there was no need to refine the entire model, but rather to create a sector model of the pilot area and perform the refinement on this region only. Figure 4-2 highlights the area that constitutes the new sector model. Henceforth, this sector model will be referred to as the 'Coarse' model.

The second grid was created by reducing the gridblock length in the x-direction from 200ft in the Coarse model to 100ft. Each gridblock was essentially split into two while retaining the properties of the original gridblock. In this way, the pore volume and oil-in-place in the pilot area are the same as the Coarse grid. The new transmissibility factors were calculated by using the following procedure:

i. Use the original transmissibility factors and grid sizes from the Coarse grid to calculate the product of the x-direction and y-direction permeability using Equation 4.1 and 4.2.

ii. Calculate the equivalent radius of the new wellblock by using the new grid sizes and Equation 4.2.

iii. Calculate the new transmissibility factor using the results from part i and ii and equation 4.1.

To validate the use of this model, the waterflood performance of the pilot producer was compared against the Coarse model. This new model will be referred to as 'Fine-x'.

The third model was created by refining the Fine-x grid in the y-direction in the proposed pilot area only. It was decided by the operator that the pilot injector needed to be between 100ft to 300ft away from the producer. Figure 4-3 highlights the area that will be refined. The refined area extends to 250ft away from the producer since it was determined from preliminary simulations on the Coarse grid that even a well-spacing of 250ft would result in a long project life.

The procedure involved in refining this grid is similar to the one used to create Fine-x. One 100ft x 50ft gridblock is now split into three 100ft x 16.67ft gridblocks, and the well is now completed in the second gridblock. This ensures that the well-spacing between pilot injector and producer is the same in all three simulation grids. This grid will be referred to as Fine-xy from here on.

To validate the use of these simulation models, the cumulative oil, oil cut, pilot injection rate and pilot producer rate are compared in Figure 4-4 - Figure 4-7. There is a small difference in injection and production rate in the Fine-x and Fine-xy grids when compared to the original and Coarse grids. However, there is very little difference in the cumulative oil recovered and oil cut.

4.3 Base Case Simulation

The purpose of this study was to perform some initial screening simulations to determine the feasibility of operating an SP pilot in this reservoir. Phase behavior experiments were performed in the laboratory and the results were matched with

UTCHEM. However, detailed coreflood parameters (such as surfactant and polymer adsorption, residual oil saturation to chemical, etc.) were not available for this particular surfactant formulation. Therefore, some assumptions were made for the parameters where no data was available, and an uncertainty analysis will be performed to look at the impact of some of these parameters on the overall success of the pilot.

4.3.1 Surfactant Phase Behavior

The surfactant formulation along with the corresponding UTCHEM input parameters are described in Table 4-3. These phase behavior experiments were performed on reservoir oil and brine and a UTCHEM match of the laboratory data is illustrated in Figure 4-8.

4.3.2 Simulation Assumptions

Surfactant adsorption was assumed to be 0.15 mg/g-rock and polymer adsorption was assumed to be approximately 14 μg/g-rock. Since this reservoir contains fairly low-permeability rock it will be important to evaluate the impact of adsorption on the overall recovery. The microemulsion viscosity was estimated to be approximately 2.5 cp at optimum salinity based on a laboratory measurement. Reservoir corefloods are currently underway to demonstrate the effectiveness of surfactant formulation in producing oil and to provide an estimate of chemical retention.

Since this reservoir has fairly low porosity, a low molecular weight polymer needs to be used to ensure efficient propagation through the reservoir. Co-polymers of acrylamide and acrylamido-tertiary-butyl sulfonate (ATBS) are more resistant to harsh environments of high salinity and temperature. They can also be manufactured to have low molecular weight. Extensive rheological data is available for this polymer at the UT laboratories, some of which is summarized by Lee et al. (2009). This data was used to obtain the necessary polymer viscosity parameters for the simulation.

The trapping number used for the base case simulation is 10,000 which is representative of mixed-wet carbonate rocks. It was assumed that the Corey-type relative permeability parameters for the end-point and exponent are 1 at high capillary numbers. It was also assumed that the residual water and oil saturation to chemical is 0% and 1% respectively. All the parameters discussed in this sub-section are listed in Table 4-4.

4.3.3 Pilot Well-Placement and Operating Conditions

Constraints regarding the placement and length of the pilot well were provided by the operator. It was suggested that the well be placed between 100ft to 300ft away from the producer in order to have a reasonable amount of time before oil bank breakthrough. All wells in the pattern follow a deviated trajectory that cuts through all the layers equally, and this criterion also needed to be maintained for the pilot well. Therefore, it was suggested that the well be between 2000ft to 4000ft long so as to get a response that is representative of all layers in this reservoir. In the base case simulation, the pilot well was placed 200ft away from the injector and is 3200ft long. As Figure 4-2 shows, the pilot well is located in an area where no high-permeability streaks are present. The bottom-hole pressure of this well will be set at 5000 psi.

The pilot producer well is also producing oil from outside the pilot area since the field will still be undergoing waterflood operations during the pilot project. To evaluate the oil recovered by chemicals from the pilot area only, the incremental oil over waterflood was calculated in each simulation.

4.3.4 Surfactant and Polymer slug sizes and concentrations

The mass of surfactant and polymer injected was designed to overcome adsorption and ensure propagation through the reservoir. The slug size of the surfactant and polymer was designed to be greater than the retardation factor, D_s. Lake (1989) discusses how this factor describes the lag of the front velocity from ideal miscible displacement. It also expresses the amount of chemical retention in pore volume units. The retardation factor is defined as,

$$D_S = \frac{(1-\varphi)\rho_S}{\varphi}\left(\frac{\omega_{3S}}{C_3}\right)_J \qquad 4.3$$

Where,

φ = Reservoir porosity

ρ_S = Reservoir rock density

ω_{3S} = Adsorbed concentration of surfactant

C_3 = Injected concentration of surfactant

The average porosity in the pilot area was calculated to be approximately 13.5%. Assuming that the rock density is 2.85 g/cc, the adsorbed concentration is 0.145 mg/g-rock and the injected concentration is 2% by weight, the retardation factor was calculated to be 0.13 pore volumes. In the base case simulation, 0.15 PV of 2% surfactant were injected. Injecting 0.3 PV of 1% surfactant would also overcome the surfactant retention but would also increase the project life time. Additionally, fractional flow theory shows that injecting a higher concentration of surfactant will reduce the breakthrough time of the oil bank, as illustrated in Figure 4-9. In this plot, the slope of the green 'waterflood line' represents the velocity of the oil bank shock front when 2% surfactant solution is used. The red line 'waterflood line' represents the velocity of the oil bank when 1%

surfactant solution is used. It can be seen that the slope is larger for the green waterflood line, meaning that the oil bank will breakthrough earlier.

The polymer concentration in the SP slug was designed to ensure that the mobility ratio between the oil bank and the SP slug was 1 or lower. A plot of the total relative mobility along with the polymer requirement is shown in Figure 4-10. From this chart, it can be seen that in order to maintain a mobility ratio 1 or lower between the oil bank and microemulsion bank, the viscosity in the SP slug needs to be at least 8 cp or higher. It is assumed that the relative permeability endpoint to water is 1. The polymer viscosity in the surfactant slug in the base case simulation is set at 9 cp.

The polymer concentration in the polymer drive was calculated to ensure that its mobility is lower than the mobility of the SP slug. Based on the microemulsion parameters and the oil and SP slug viscosity, the maximum microemulsion viscosity is approximately 11cp. A plot of the microemulsion viscosity versus the oil concentration in the surfactant phase is shown in Figure 4-11. The viscosity in the drive was chosen to be 12 cp, and was achieved by injecting 10000 ppm. The retardation factor of the polymer drive was calculated to be 0.026 by assuming that the adsorbed concentration is 14 μg/g-rock. To ensure complete and efficient displacement of the SP slug through the reservoir, the polymer drive size was chosen to be 1 PV. Additional simulations will be performed later to identify the optimum polymer drive size and concentration.

4.3.5 Base Case Simulation Results

The results for the base case simulation using the three different simulation grids are shown in Figure 4-12 and Figure 4-13. In the first chart, the incremental oil recovered over waterflood is plotted against the pore volumes of fluid injected. In the second chart, the recovery factor is plotted against time. As mentioned earlier, the sizes for the SP, polymer drive and water chase are 0.15 PV, 1PV and 1PV respectively.

There are a few interesting observations that can be made from these results. Firstly, the incremental oil recovery improves significantly as the grid size is refined. In fact, each grid refinement step shows an additional 10% of the oil in place recovered, as highlighted in Figure 4-13. Veedu (2010) has shown that the concentrations of injected chemicals can get artificially diluted when coarse grids are used. One of the main implications of this is that the surfactant concentration could propagate below the critical micelle concentration or that the salinity could propagate below the Type III window; both of which will significantly reduce the amount of residual oil that gets mobilized. This would explain the increase in recovery that is observed when the simulation grid is refined.

The second interesting observation is that the higher polymer concentration in the Fine-x and Fine-xy grids will result a more favorable mobility ratio and better sweep around the injector. This is illustrated in Figure 4-14 and Figure 4-15 which compare the polymer concentration and viscosity in the Coarse and Fine-xy grids. Figure 4-16 and Figure 4-17 compare the oil saturation at the end of the polymer drive, and a significant difference can be seen between the two grids.

Finally, the increase in the sweep efficiency of the surfactant solution around the injector means that the relative permeability also improves more evenly in the pilot area. Figure 4-13 shows that the project life decreases considerably when the grid is refined and that the negative incremental oil over waterflood is the least in the Fine-xy simulation. As discussed earlier, the injection rate during waterflood is almost the same for all three grids after correcting the transmissibility factors in each simulation grid.

The results of this base case simulation highlight the synergistic effects that can be missed when using coarse simulation grids. The increase in oil recovery and reduction in project life that was observed with grid refinement will significantly improve the economics. However, the project life of 10 years that was observed with the Fine-xy grid is still too long for a pilot project. The negative incremental recovery observed early in the project will also adversely affect the NPV of this project. Finally, very high concentrations of polymer are required to have a stable flood and it is likely that an unstable displacement flood will have to be evaluated for this field in order to improve the project economics. The next section in this chapter will focus on identifying a design that will yield good recovery without a significant delay in oil bank breakthrough.

4.4 Optimization Studies

The optimization simulations that will be performed include reducing the surfactant concentration, polymer concentration and polymer drive size. Surfactant floods without any mobility control will also be studied. All the simulations described are unstable displacement processes and will be performed on the Fine-xy grid.

4.4.1 Surfactant Flood without Mobility Control

The purpose of this set of simulations was to estimate the recovery from an unstable surfactant displacement process. The base case results show that polymer will reduce the injectivity significantly in this low permeability reservoir. However, injecting a surfactant solution only will increase the relative permeability to water; thereby increasing the injectivity. The trade-off to this is that the macroscopic sweep efficiency will be lower than that of a SP solution, and maybe even lower than that of a brine solution because of the relative permeability enhancement.

Two surfactant flood simulations will be performed in this sub-section. The first simulation, referred to as RunSF1, consists of 0.15 PV of 2% surfactant followed by 2 PV of water. The salinity gradient in this simulation is the same as the base case - the surfactant was injected at 0.7875 meq/ml, followed by 1 PV of water at 0.65 meq/ml and 1 PV of water at 0.0381 meq/ml. In the second simulation, referred to as RunSF2, 0.3 PV of 1% surfactant at 0.7875 meq/ml was followed by 1 PV of water at 0.65 meq/ml and 1 PV of water at 0.0381 meq/ml. The results are shown in Figure 4-18 and Figure 4-19.

RunSF1 and RunSF2 recover approximately 28% and 38% of incremental oil over waterflood respectively. As expected, the recovery is lower than the base SP case because of the poorer sweep efficiency. However, Figure 4-19 shows that the project life reduces very significantly compared to the base case. Even though the same mass of surfactant is injected in both these sensitivity simulations, RunSF2 recovers more oil because the salinity gradient is not as steep.

4.4.2 Surfactant Concentration in SP Flood

The purpose of injecting a more dilute surfactant solution would be to defer the chemical cost, which in turn would improve the NPV of the project if the oil recovery is comparable with the base case. As shown earlier, the mass of surfactant injected needs to overcome surfactant adsorption and retention. In addition to the base case conditions, injecting a 1% surfactant solution for 0.3 PV will also overcome adsorption. This injection scenario was simulated and is referred to as RunSC1. Also, since the swept pore volume is likely to be less than 100% because of reservoir heterogeneities, it is possible that a smaller surfactant mass will still overcome retention. In the second simulation, referred to as RunSC2, 0.15 PV of 1% surfactant solution will be injected. In the third simulation, referred to as RunSC3, 0.15 PV of 3% surfactant solution will be injected.

The polymer concentration and polymer drive size in all these simulations are kept the same as the base case. The results are shown in Figure 4-20 and Figure 4-21.

From these charts, it can be seen that injecting a surfactant mass that is equal to or greater than the base case has a minor effect on the results. However, in RunSC2 the surfactant mass injected is half of the base case, and should theoretically not overcome adsorption. This is reflected in the results which show that the recovery factor gets reduced to 44% (from 63% in the base case). Also, since the surfactant mass is under optimum in RunSC2, the same relative permeability enhancement is not observed when compared to the base case. As a result, the duration of the project life increases.

The results from RunSC1 and RunSC3 are very similar to the base case. This implies that the base case design of the surfactant slug is probably closest to the optimum design. RunSC1 recovers approximately the same amount of oil but the project life has increased. RunSC2 recovers approximately 4% more incremental oil and has a shorter project life compared to the base case, but a more detailed economic analysis is required to determine if this offsets the extra cost of surfactant.

4.4.3 Polymer Concentration in the SP and Polymer Drive slugs

The purpose of this set of simulations was to optimize the flood design by finding a trade-off between sweep efficiency and breakthrough time of the oil bank. In the first sensitivity simulation, referred to as RunPC1, the polymer viscosity in the SP slug was reduced to 2 cp and the viscosity in the polymer drive was reduced to 4 cp. In the second simulation, referred to as RunPC2, the polymer viscosity in the SP slug was reduced further to 1 cp and the viscosity in the polymer drive was 2 cp. The results are highlighted in Figure 4-22 and Figure 4-23.

From the results it can be seen that the simulation results for RunPC1 appear to out-perform the base case. This result might be attributed to the higher permeability reduction factor in the base case because of the higher polymer concentration. The polymer concentration is 9500 ppm in the base case and 3850 ppm in RunPC1. Some sensitivity simulations will be performed on this parameter and the results will be discussed in the next section.

The results for RunPC2 show slightly less incremental oil recovery than the base case. This was expected since there is significantly less mobility control in this simulation. As Figure 4-23 shows, the final oil recovery in this simulation is approximately 58% of the OIP. Overall, both of the polymer concentration sensitivity simulations show little difference in incremental oil recovery when compared to the base case. The lower polymer cost and faster oil breakthrough would mean that these two scenarios are more economic than the base case. However, these sensitivity simulations are also likely to be more sensitive to changes in heterogeneities and other reservoir uncertainties. Therefore, it should be noted that the recovery from these unstable displacements might be overstated because of insufficient reservoir heterogeneity in the simulation model. As discussed earlier, the grid refinement procedure involved 'splitting' one grid into multiple grids while retaining the original gridblock properties. Ideally, the fine-scale simulation grids would have gridblock properties that vary on a gridblock-by-gridblock basis.

4.4.4 Polymer Drive size

In this sub-section, the polymer drive size in the base case, RunPC1 and RunPC2 were all reduced to 0.5 PV. These simulations runs will be referred to as Base_2, RunPD1 and RunPD2 respectively, and the results are highlighted in Figure 4-24 and

Figure 4-25. It can be seen that the latter two simulations are much more sensitive to a reduction in the polymer drive size. This is because RunPD2 is a much more unstable displacement process compared to RunPD1, which in turn is less stable than Base_2.

4.4.5 Pilot Well Spacing

The last sensitivity simulation involved reducing the well-spacing in order to accelerate oil production. A trade-off needs to be established because even though the breakthrough time of the oil bank is reduced with closer well-spacing, so is the volume of incremental oil. In the base case simulation, the well-spacing is 200 ft. Select sensitivity simulations from the previous sections will be repeated on a reduced well-spacing of 150 ft. In the first sensitivity simulation, referred to as Base_3, the base case simulation will be repeated on the reduced well-spacing pattern. In the second simulation, the concentration of polymer will be reduced to achieve a viscosity of 2 cp in the SP slug and 4 cp in the polymer drive (similar to RunPC1). In the third simulation, the composition of the injected slugs is the same as the base case, but the polymer drive size will be reduced to 0.5 PV (similar to Base_2). Figure 4-26 and Figure 4-27 highlights the results.

It can be seen that the overall trend of results observed with the reduced well-spacing pattern is the same as the results observed on the original well-spacing. The recovery factor does reduce by approximately 10% when comparing the base case and Base_3 simulations. However, the project life reduces significantly for the reduced well-spacing. The project life of Base_3 has reduced by almost 4 years when compared against the base case simulation.

4.4.5 Summary

The simulations in this section highlight the importance of establishing a trade-off between good sweep efficiency and fast oil breakthrough. While the base case simulation does recover the most cumulative oil, the economics of this simulation are not favorable because of the high chemical cost, the slow oil production and the negative incremental oil observed early in the project life. The surfactant flood simulations do have the shortest project life but the incremental recovery is less than half of the base case because of poor sweep efficiency. In fact, even injecting a small amount of polymer to increase the viscosity of the surfactant slug to 1cp will significantly improve the recovery. The results of this section also highlight how it is important to inject a sufficient mass of surfactant so as to overcome adsorption. The benefit is not only seen in the amount of oil recovered but also in the injectivity.

4.5 UNCERTAINTY ANALYSIS

Since there was no coreflood data available for this surfactant formulation, assumptions had to be made for some of the parameters. An uncertainty analysis was then performed on select parameters such as surfactant adsorption, in-situ effective shear rate coefficient (γ_c) and the permeability reduction factor.

4.5.1 Surfactant Adsorption

In the base case simulation, surfactant adsorption of 0.145 mg/g-rock was used. Since this is a fairly uncertain value, some additional simulations were performed to investigate the impact of increasing the adsorption to 0.20 mg/g-rock. However, since this is a very low-permeability rock, surfactant retention needs to be carefully evaluated by using reservoir corefloods. The results are shown in Figure 4-28 and Figure 4-29. In RunSA1, the only change from the base case simulation is the increase in surfactant adsorption to 0.20 mg/g-rock. In RunSA2, the concentration in the SP slug was reduced to 1% (Same as RunSC2) and the adsorption was increased to 0.20 mg/g-rock. The retardation factor, D_s, for RunSA1 and RunSA2 is 0.18 and 0.37 respectively.

Similar to the simulations where surfactant concentration was investigated, it can be seen that the amount of surfactant in the fluid has a significant impact on both oil recovery and injectivity. It is also interesting to note that RunSA1 (0.15PV x 2% surfactant) is less sensitive than RunSA2 (0.15PV x 1% surfactant) when the surfactant adsorption is increased.

4.5.2 In-Situ Effective Shear Rate

The in-situ shear rate is modeled by the modified Blake-Kozeny capillary bundle equation for multi-phase flow (UTCHEM Technical Documentation, 2011).

$$\dot{\gamma}_{eq} = \left[\frac{3n+1}{4n}\right]^{\frac{n}{n-1}} \frac{4uC}{\sqrt{8\bar{k}k_{rl}\varphi S_l}} \qquad 4.4$$

Where,

$\dot{\gamma}_{eq}$ = Equivalent Shear Rate

n = Power Law Exponent

u = Darcy Velocity

C = Shear Rate Coefficient

$\bar{k}$ = Base Permeability

k_{rl} = Relative Permeability of Phase l

φ = Porosity

S_l = Saturation of Phase l

The shear rate coefficient, C, is a correction factor for non-ideal effects. These effects include slip at the pore walls which implies that this coefficient is a function of permeability and porosity. As the permeability decreases, the equivalent shear rate increases, thereby reducing the viscosity of the polymer as long as it is within the shear-thinning region. So since shear rates are high at the wellbore, this can have a significant impact on injectivity. In the base case simulation, the value for C is 25. An additional simulation was performed by increasing the value of C to 50, while keeping the rest of the parameters constant. It is important to note that even a value of 50 might not be high enough for this low-permeability reservoir. Since the permeability varies on a gridblock-by-gridblock basis, the value of C also needs to be calculated for each gridblock. The results are shown in Figure 4-30 and Figure 4-31.

From these charts it can be seen that the incremental oil recovered is almost the same between both sets of simulations. However, there is a very significant increase in injectivity with the project life decreasing by approximately four and a half years.

4.5.3 Permeability Reduction Factor

The permeability reduction factor is defined as the ratio of the effective permeability of water to the effective permeability of polymer. The permeability factor will increase as the permeability of the porous medium decreases or if the concentration of polymer increases. In the base case simulation, the permeability reduction factor is approximately 3.23 for both the SP and polymer drive slugs. In RunPC1, the polymer concentration is lower and the permeability reduction factor is approximately 3.21 in the SP slug and polymer drive. Additional simulations were performed where the permeability reduction factor was reduced to approximately 2.1 for the base case and RunPC1. These runs are referred to as RunPR1 and RunPR2 respectively, and the results are shown in Figure 4-32 and Figure 4-33.

From these charts it can be seen that there is very little difference in terms of incremental oil recovered when the permeability reduction factor is reduced. However, the project life of the base case simulation reduces significantly. The project life of RunPR2 when compared to RunPC1 does not reduce as much since the polymer concentration is these two simulations are lower than the base case.

The incremental oil recovery is higher for RunP2 (lower polymer concentration) than RunPR1 (same polymer concentration as base case). However, the difference in incremental oil between these two simulations runs is less than the difference between RunPC1 and the base case. Also, the recovery from RunPR1 is slightly higher than the base case, and the only difference between the two simulations is the permeability reduction factor.

4.5 CONCLUSIONS

The goal of this chapter was to demonstrate the feasibility of conducting a Surfactant-Polymer pilot project in a low-permeability, high temperature reservoir with horizontal wells and to identify key parameters that have a significant impact on the success of the project. The results of the grid refinement studies show the importance of using a fine-scale grid to model unstable displacement processes. The recovery factor increases by 22% between the coarsest and finest simulation grids used in this study. It is very difficult to accurately capture viscous fingers unless very fine grids are used.

A summary of all the simulations performed in this chapter is provided in Table 4-6. The importance of injecting sufficient surfactant to overcome adsorption and propagate above the critical micelle concentration is demonstrated here. The benefits were observed not only in the amount of incremental oil recovered, but also in the reduction in project life that arises because of the enhancement of relative permeability to water (and the subsequent enhancement in injectivity). It was also demonstrated how even a small increase in the viscosity of the SP slug will have a significant effect on the sweep efficiency and incremental oil recovery. The most economical scenarios in terms of favorable chemical cost per barrel and project life are RunPC2, RunPD1 and RunPD2; all three of which are unstable displacement processes. Finally, the results of this chapter also demonstrate some strategies to optimize the slug design and identify some reservoir uncertainties that can have a significant impact on the project life.

Table 4-1: Fluid Properties

Water Viscosity (at reservoir temperature)	0.3 cp
Oil Viscosity (at reservoir temperature)	1.732 cp
Formation Brine Composition	Total Anion = 1.0551meq/ml Total Divalent Cation = 0.1019 meq/ml
Injected Brine Composition	Total Anion = 0.0381meq/ml Total Divalent Cation = 0.0115meq/ml
IFT	26 dynes/cm

Table 4-2: Simulation Model Properties

Model Size	39600ft x 4150ft x 12.32ft
Grid size	200ft x 50ft x 2.04ft (Layer 1 and 2) 200ft x 50ft x 4.12ft (Layer3 and 4)
Average Porosity	12.5%
Average Permeability	3 md
Vertical Permeability	$k_v/k_h = 0.25$
Initial Oil Saturation (before ASP)	46%
Reservoir Temperature	90°C
Initial Pressure	3800 psi
Water/OilRelative Permeability - Rock Type 1	$S_{orw} = 0.208$; $S_{wrw} = 0.05$ $k_{ro}° = 0.675$; $k_{rw}° = 0.28$ $e_o = 3.3$; $e_w = 3.2$
Water/Oil Relative Permeability - Rock Type 1	$S_{orw} = 0.232$; $S_{wrw} = 0.05$ $k_{ro}° = 0.61$; $k_{rw}° = 0.25$ $e_o = 2.1$; $e_w = 3$

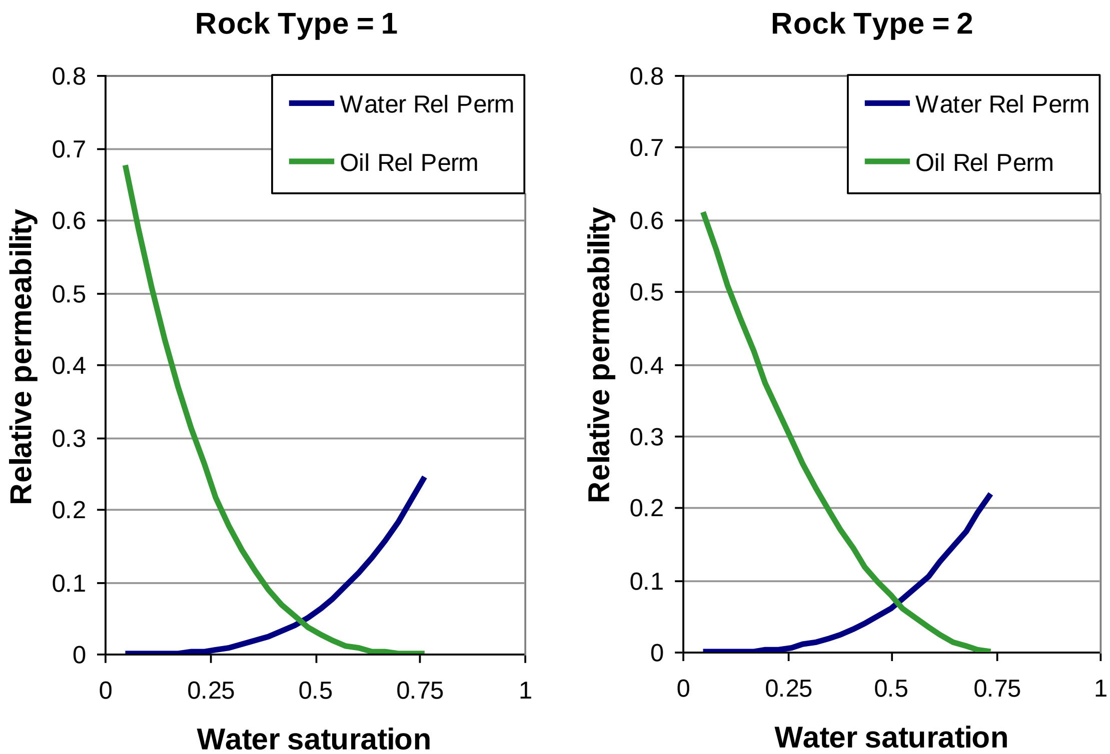

Figure 4-1: Relative Permeability Curves for Rock Type 1 and 2

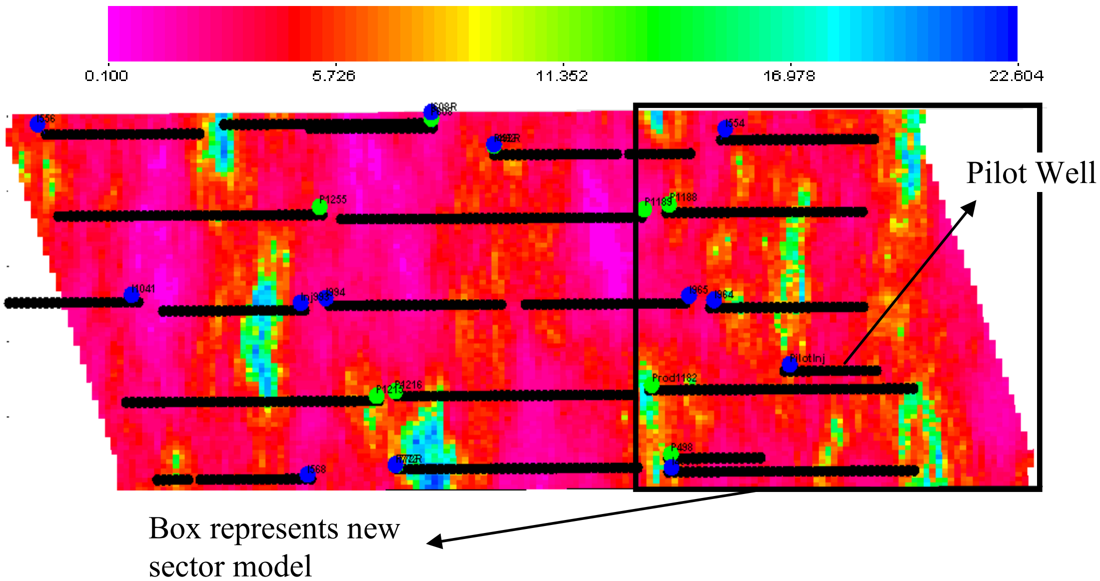

Figure 4-2: Orginal Simulation Grid with the proposed Sector Model Highlighted

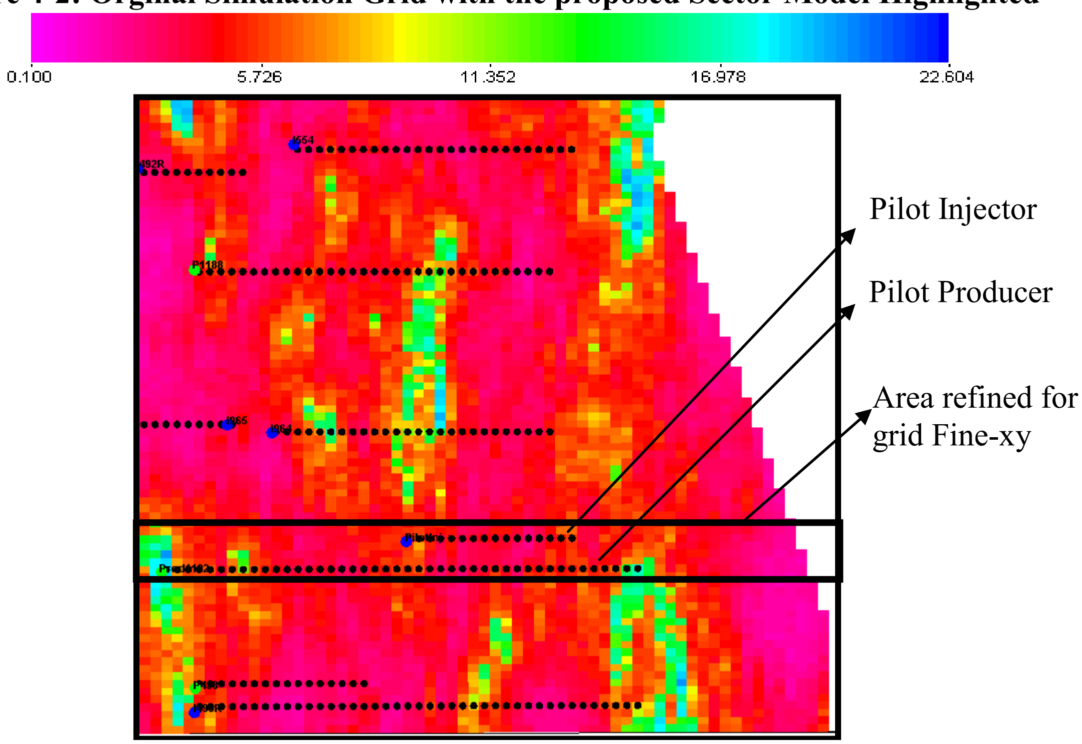

Figure 4-3: Map of 'Coarse' Grid with proposed refined area

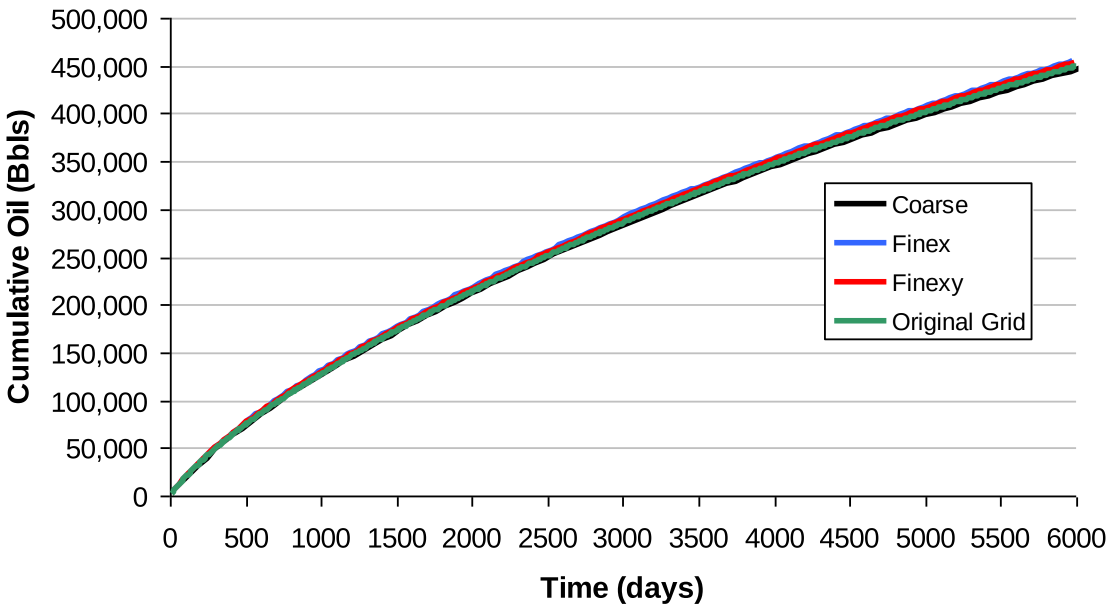

Figure 4-4: Cumulative Oil Comparison for the Different Simulation Grids

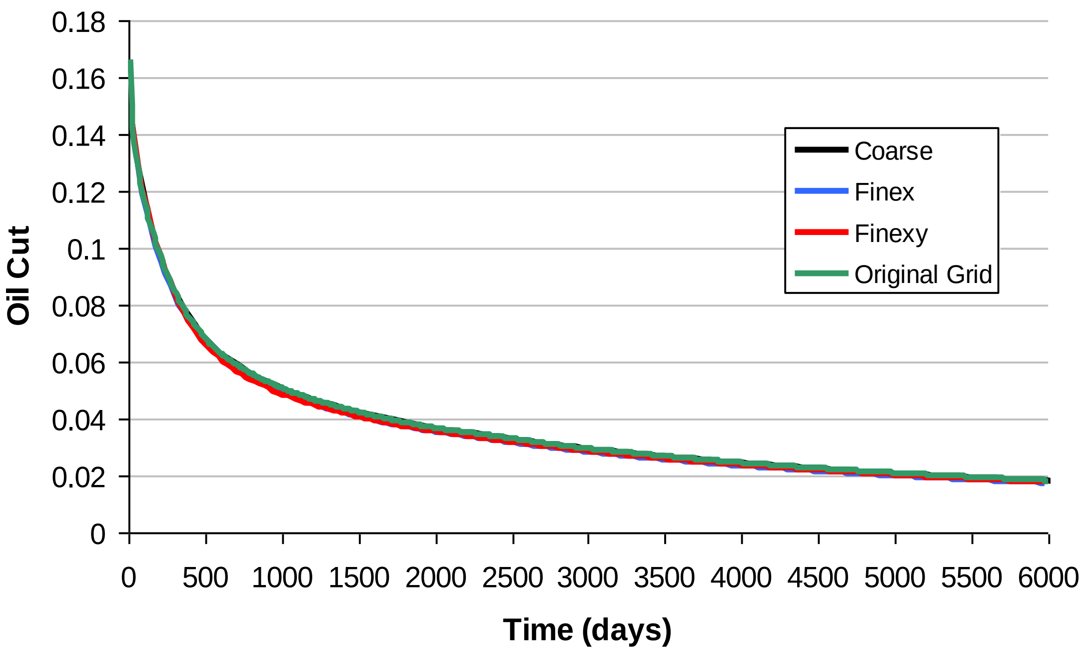

Figure 4-5: Oil Cut Comparison for Different Simulation Grids

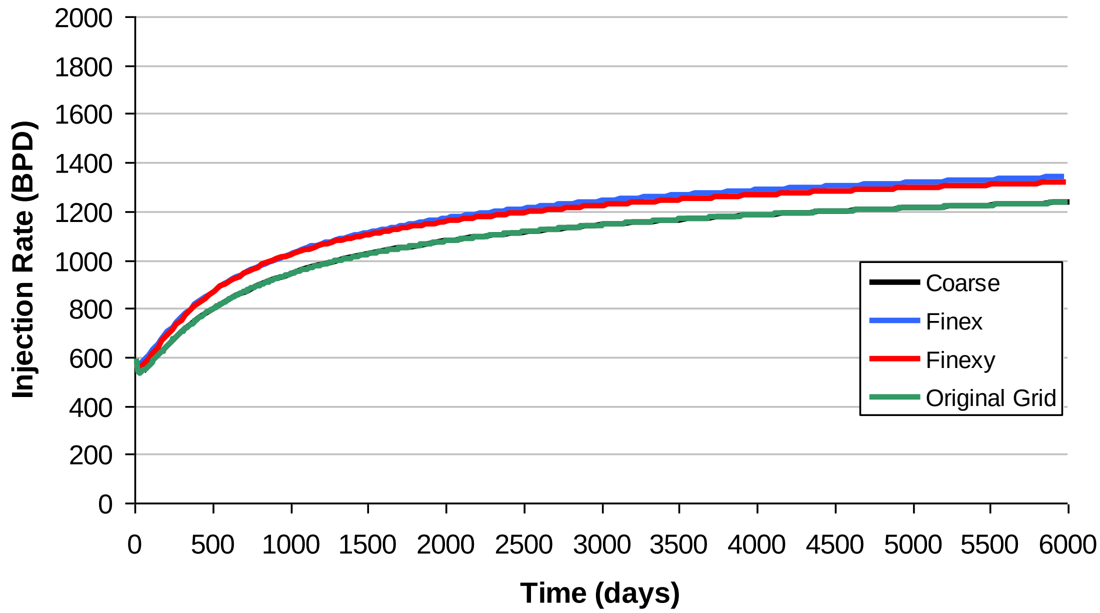

Figure 4-6: Injection Rate Comparison for Different Simulation Grids

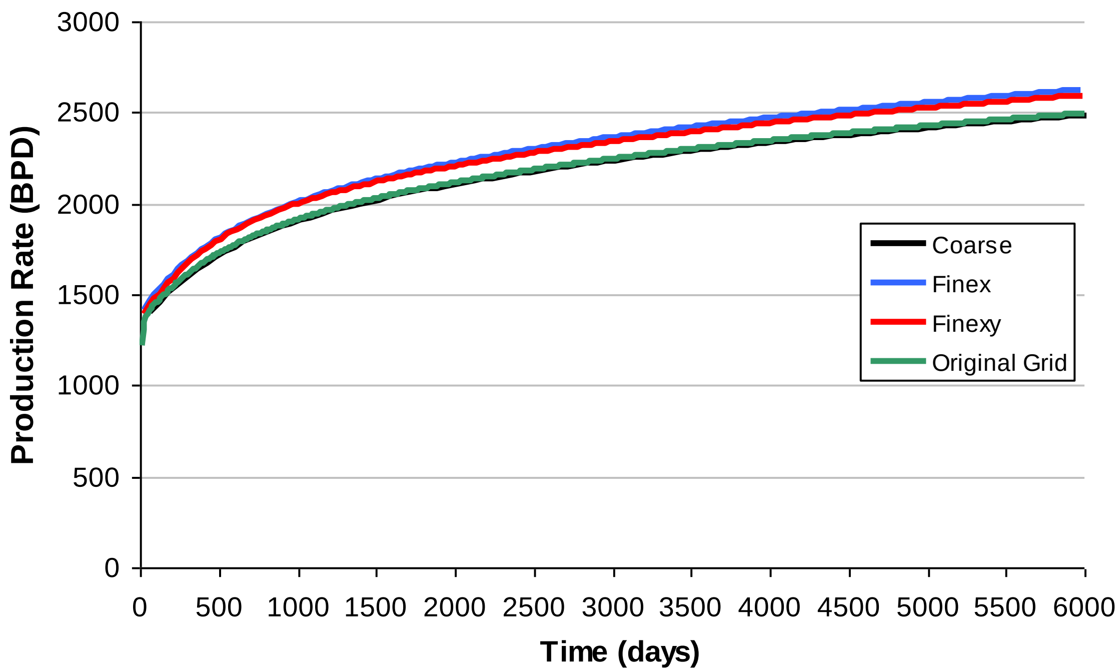

Figure 4-7: Production Rate Comparison for Different Simulation Grids

Table 4-3: Surfactant Phase Behavior Parameters

Surfactant Formulation	0.5% C28-25PO-25EO-COONa, 0.5% Petrostep S2, 0.5% TEGBE
Solubilization Ratio at optimum salinity	32.5
Optimum Salniity	0.7875 meq/ml
Sanlinity Window	CSEU: 0.860 meq/ml CSEL: 0.715 meq/ml
Hand's Rule Parameters	HBNC70: 0.020 HBNC71: 0.014 HBNC72: 0.030

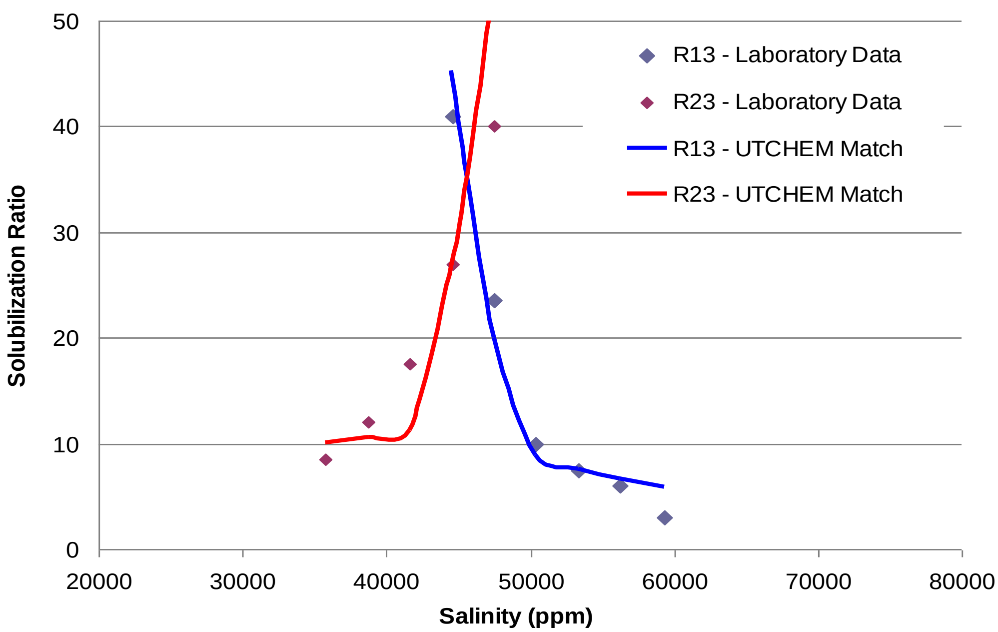

Figure 4-8: UTCHEM Match of Phase Behavior

Table 4-4: Assumed Input Parameters

Surfactant Adsorption	0.145 mg/g-rock
Polymer Adsorption	14µg/g-rock
Microemulsion viscosity	2.5 cp at optimum salinity
Trapping Number Parameters	Water = 1865 Oil = 10,000 Microemulsion = 364
Relative Permeability Parameters (at High Capillary Number)	$S_{orc} = 0.01$; $S_{wrc} = 0.0$ $k_{ro}° = 1$; $k_{rw}° = 1$ $e_o = 1$; $e_w = 1$

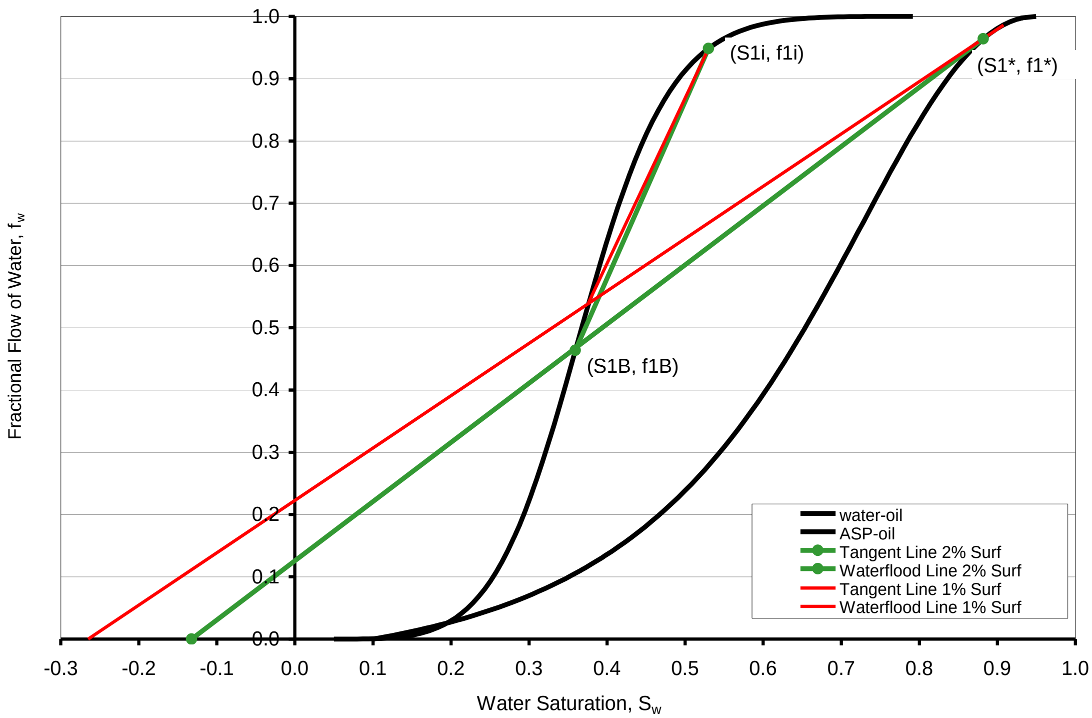

Figure 4-9: Fractional Flow Curve - Effect of Surfactant Concentration

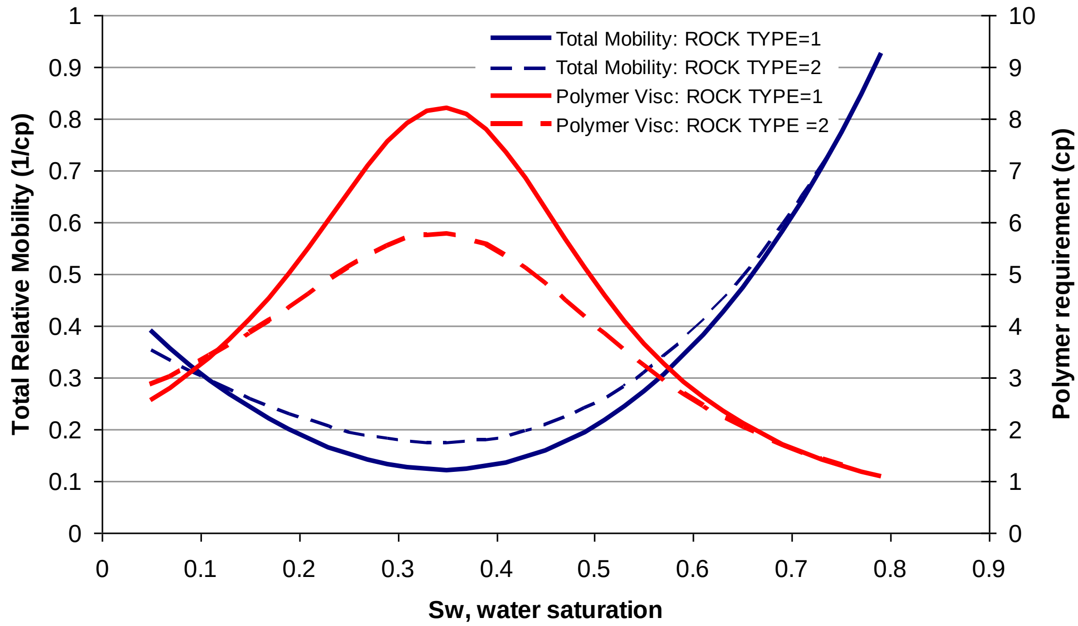

Figure 4-10: Plot of Total Relative Mobility and Corresponding Polymer Requirement

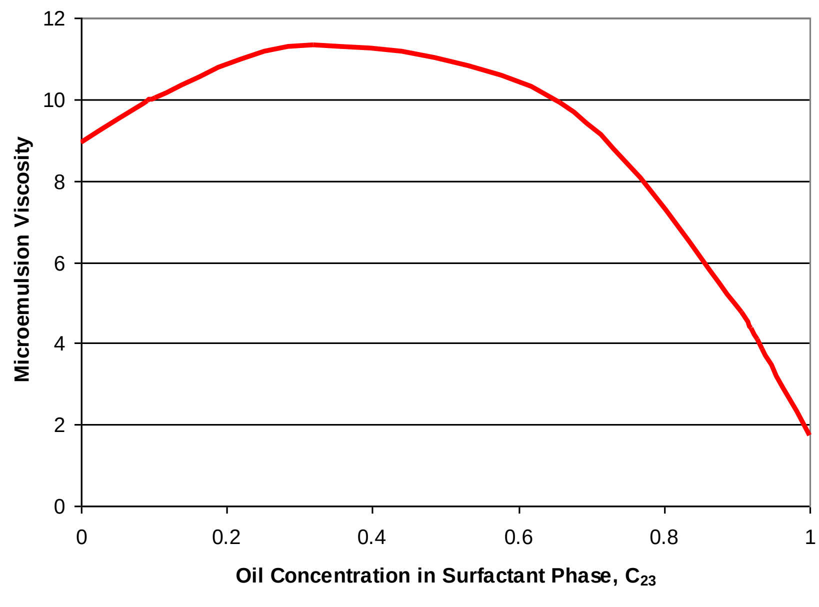

Figure 4-11: Microemulsion Viscosity

Table 4-5: Base Case Design

Pilot Injector Constraint	Pressure = 5000psi
Producer Well Constraint	Pressure = 600 psi
Pore Volume (Pilot Area)	176,000 bbls
Oil-in-place (Pilot Area)	81,300 bbls
Pilot Injector Length	3200 ft
Pilot Well-Spacing	200 ft
Pilot Producer Length	8800 ft
SP Slug	0.15 PV 2% Surfactant 9500 ppm polymer 0.7875 meq/ml
Polymer Drive	1 PV 11000 ppm polymer 0.65 meq/ml
Water Chase	1 PV 0.0381 meq/ml

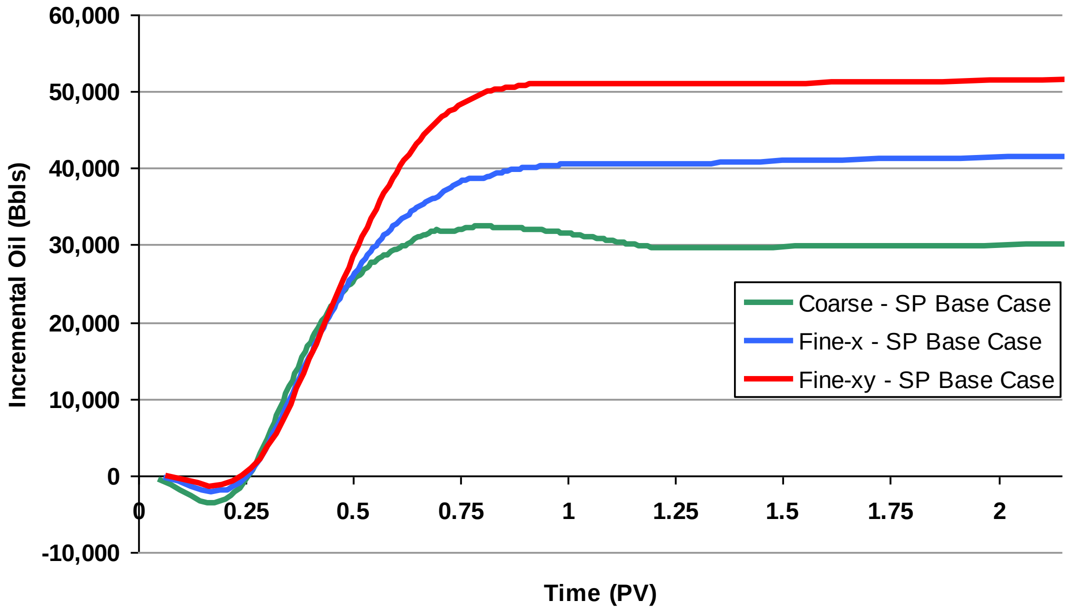

Figure 4-12: Incremental Oil vs. PV injected for Different Simulation Grids

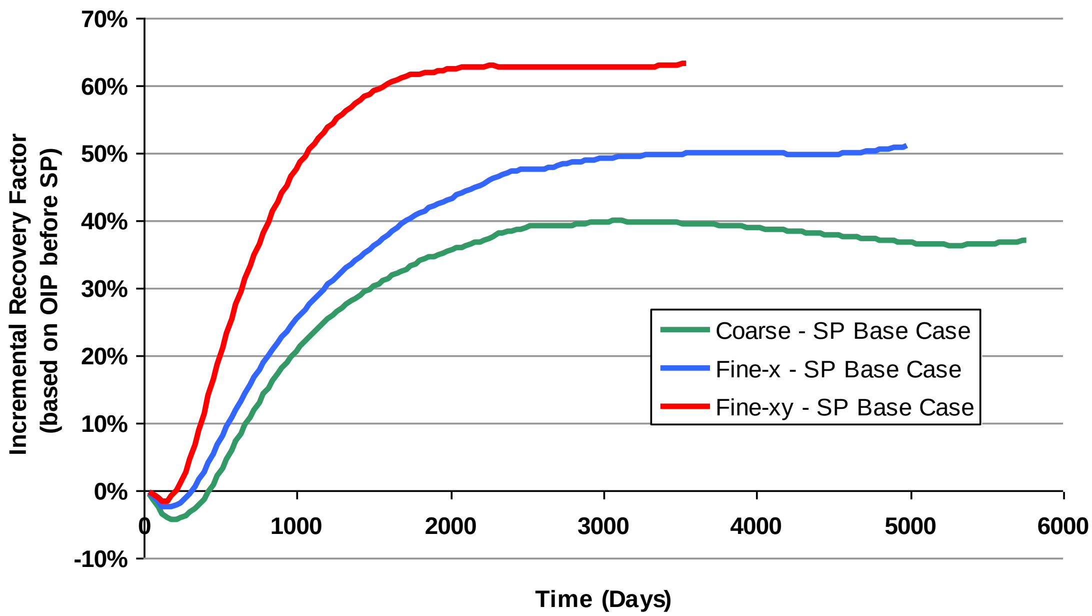

Figure 4-13: Recovery Factor vs. Time for Different Simulation Grids

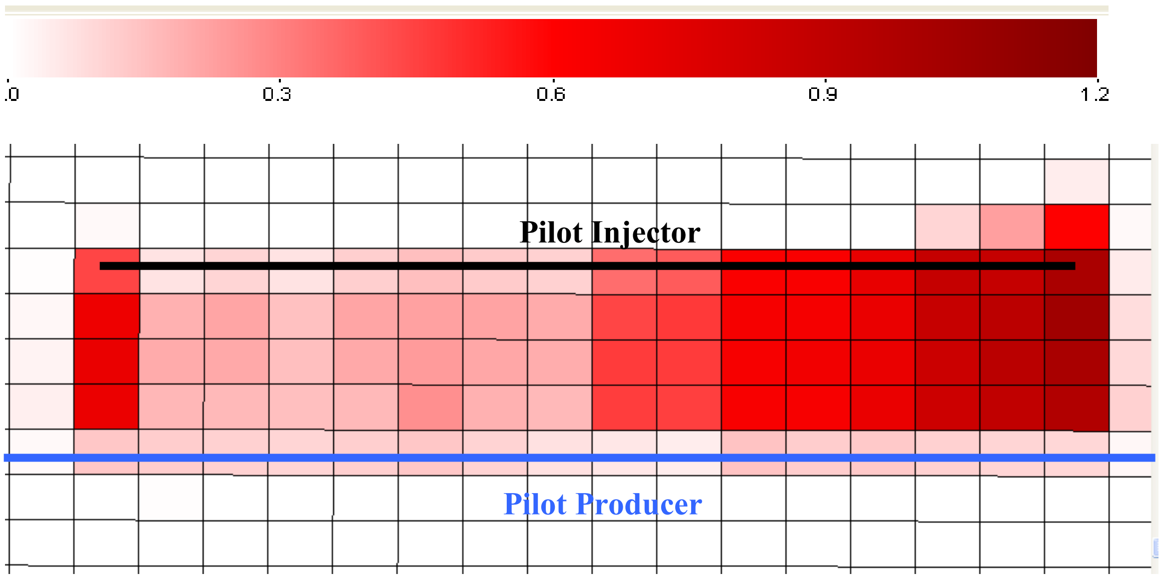

Figure 4-14: Polymer Concentration (wt%) at End of Polymer Drive (Coarse Grid)

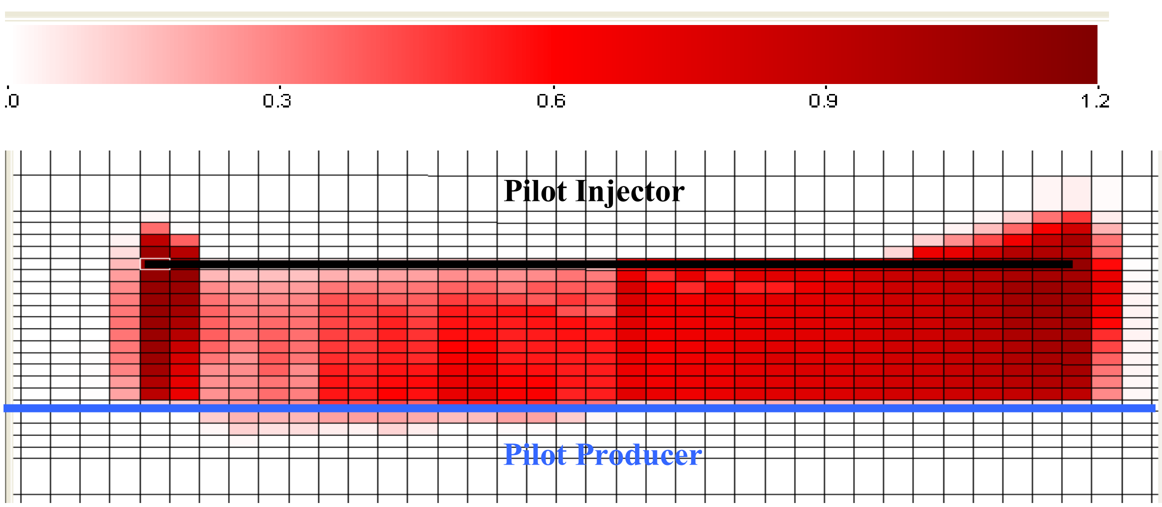

Figure 4-15: Polymer Concentration (wt%) at End of Polymer Drive (Fine-xy Grid)

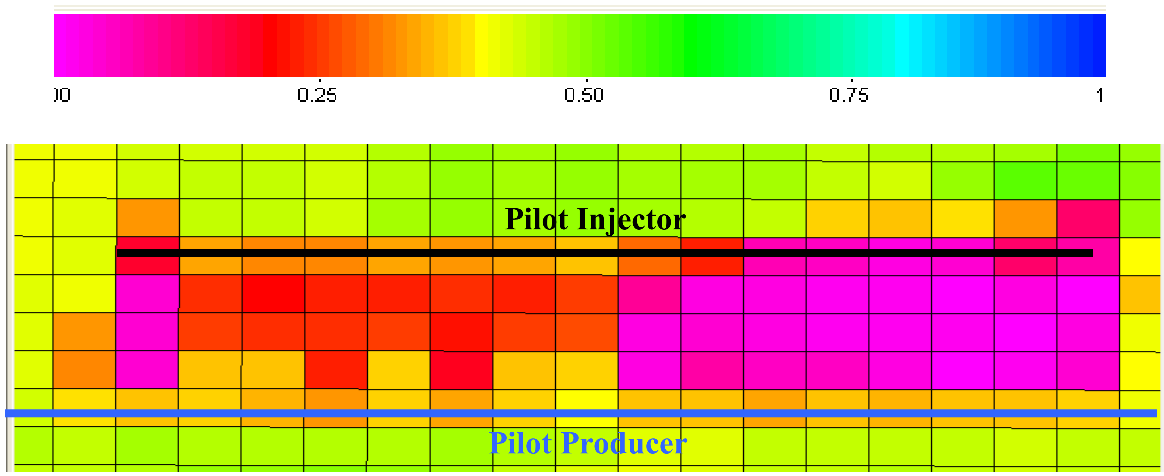

Figure 4-16: Oil Saturation at End of Polymer Drive (Coarse Grid)

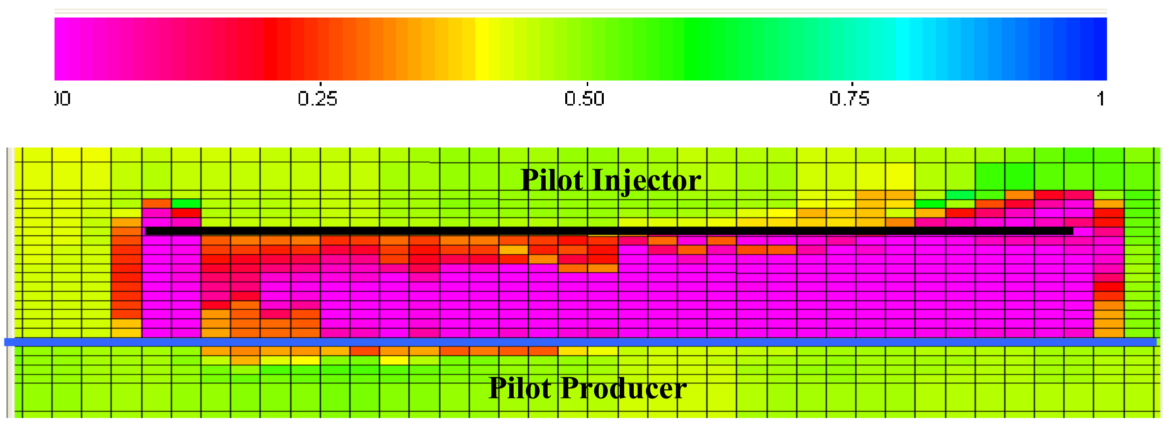

Figure 4-17: Oil Saturation at End of Polymer Drive (Fine-xy Grid)

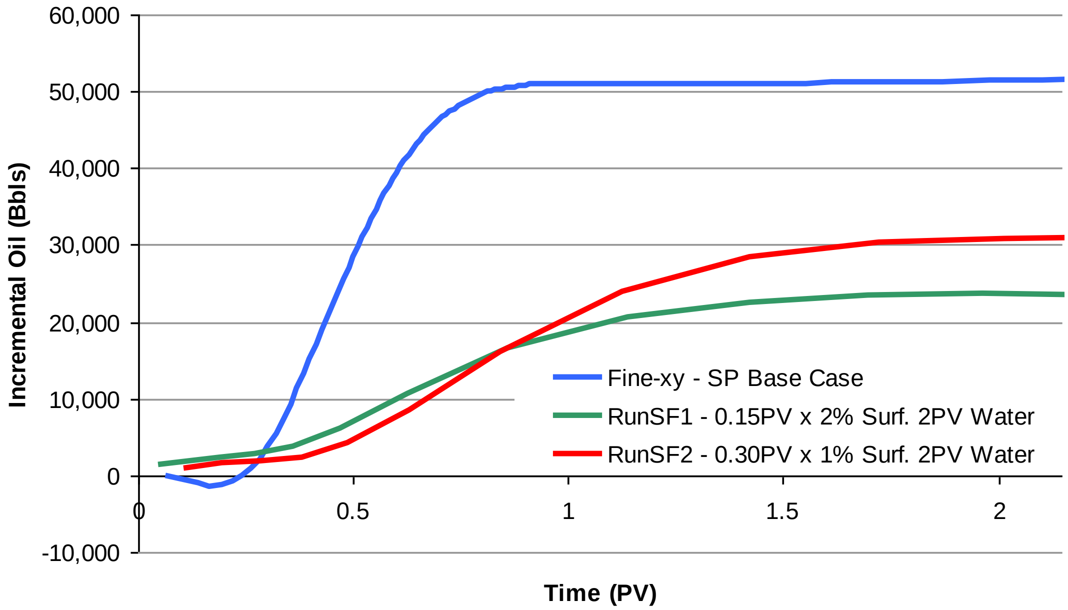

Figure 4-18: Surfactant Flood Simulations - Incremental Oil vs. PV Injected

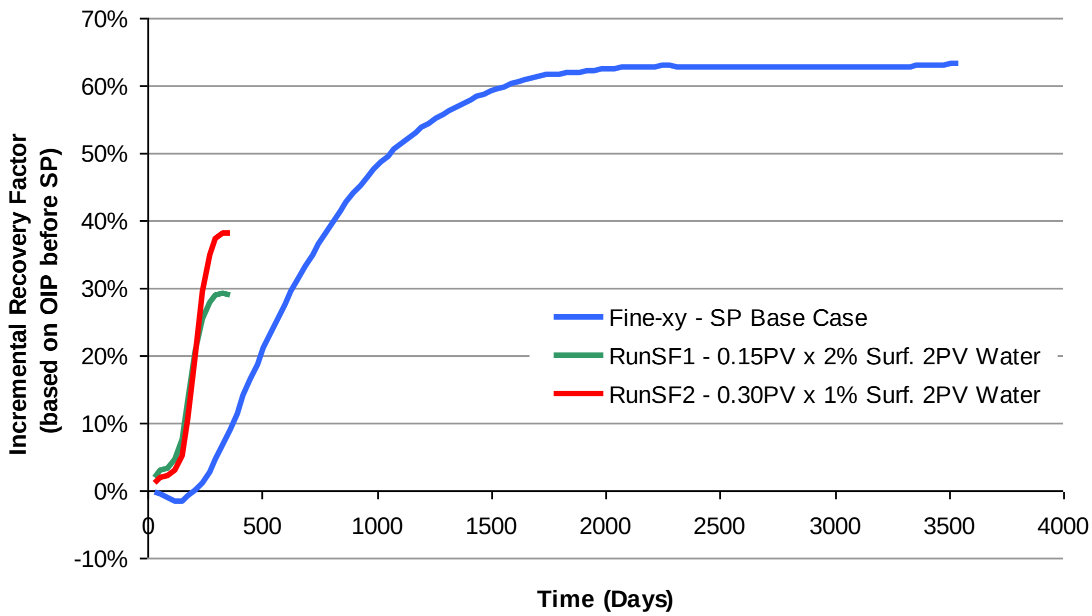

Figure 4-19: Surfactant Flood Simulations - Recovery Factor vs. Time

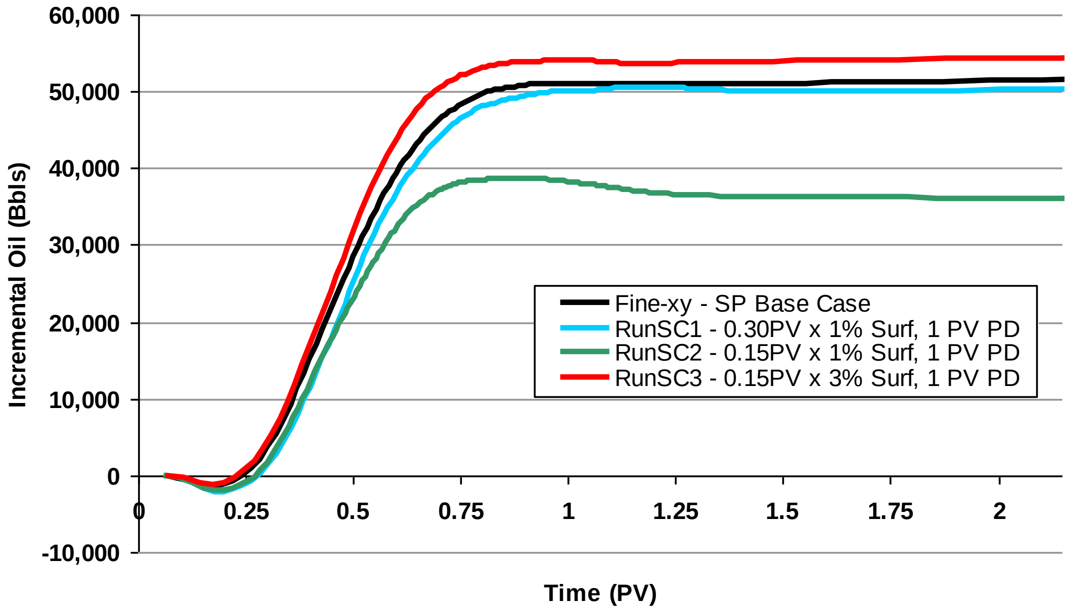

Figure 4-20: Surfactant Concentration Simulations - Incremental Oil vs. PV Injected

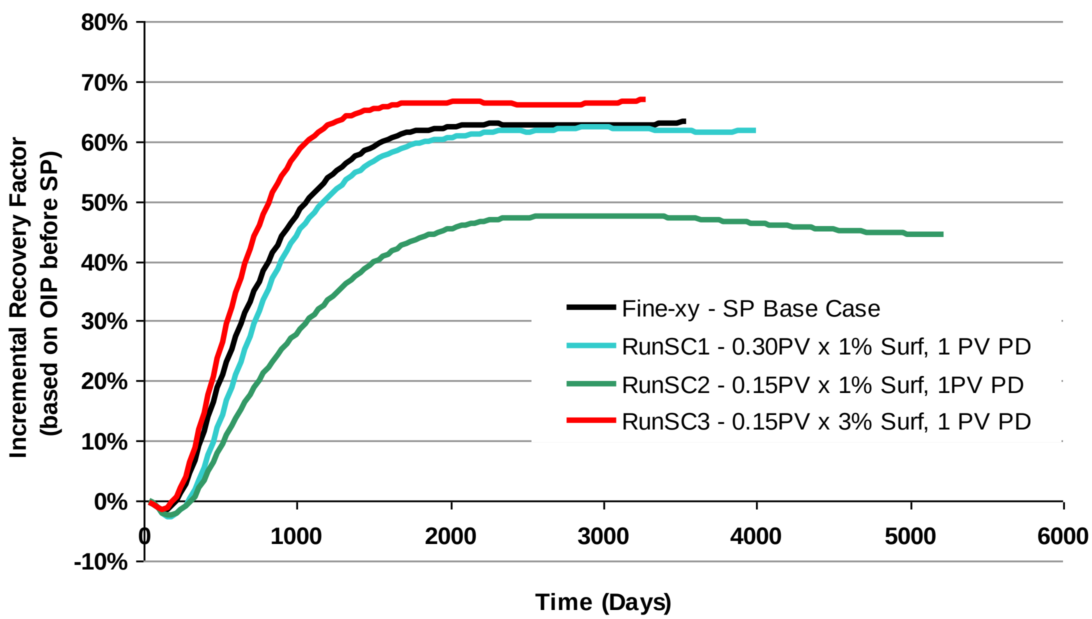

Figure 4-21: Surfactant Concentration Simulations - Recovery Factor vs. Time

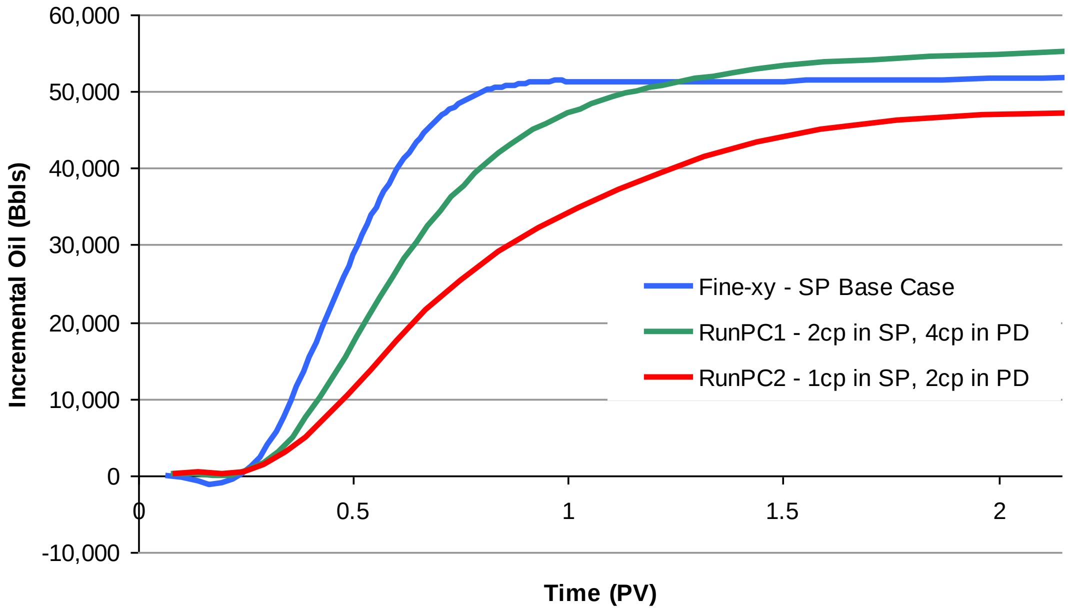

Figure 4-22: Polymer Concentration Simulations - Incremental Oil vs. PV Injected

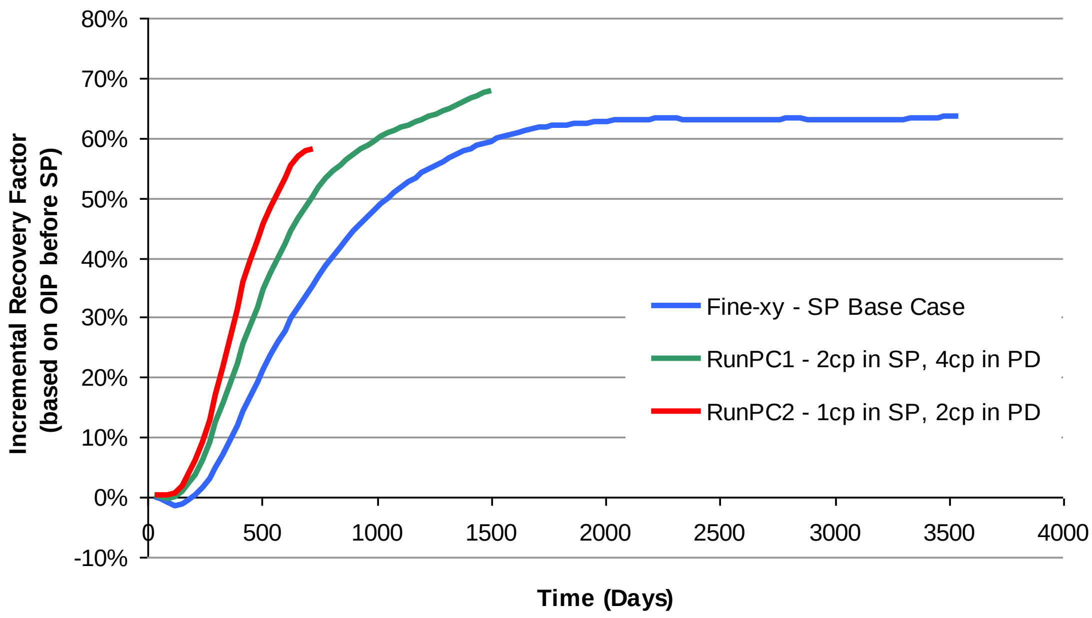

Figure 4-23: Polymer Concentration Simulations - Recovery Factor vs. Time

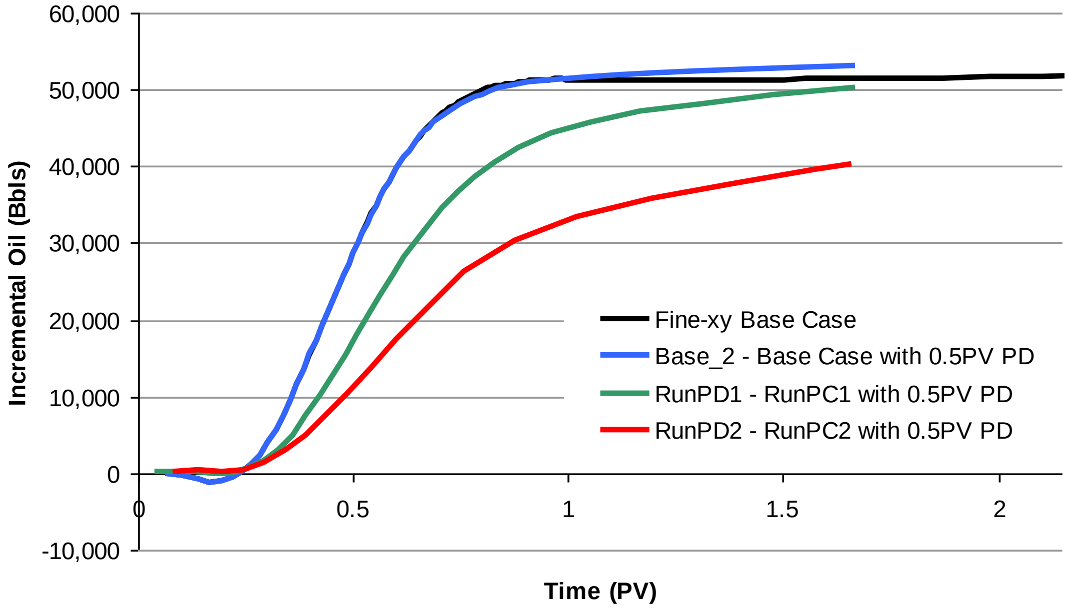

Figure 4-24: Polymer Drive Simulations - Incremental Oil vs. PV Injected

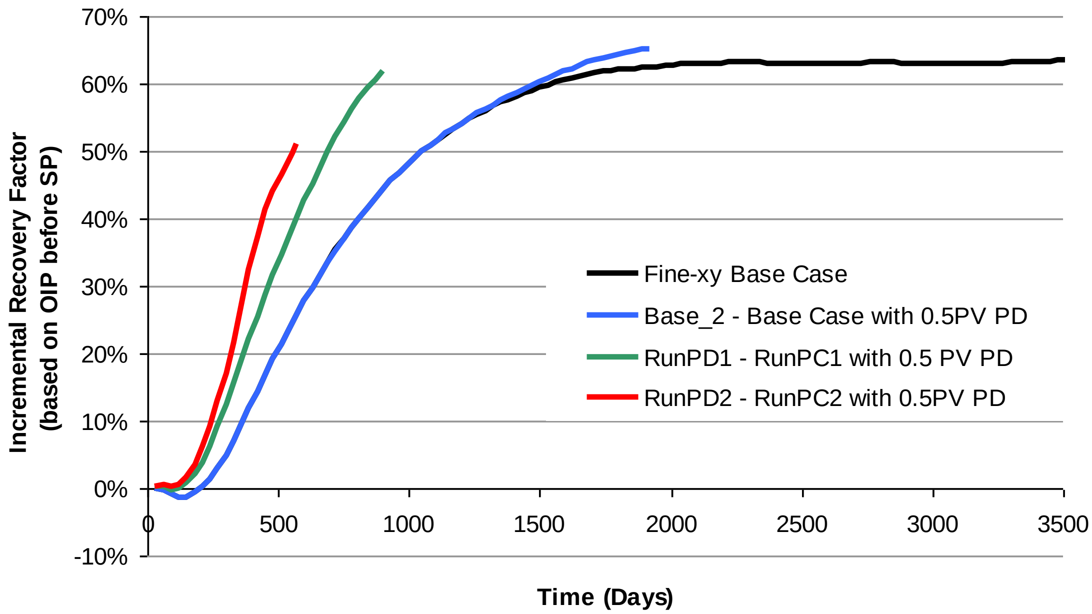

Figure 4-25: Polymer Drive Simulations - Recovery Factor vs. Time

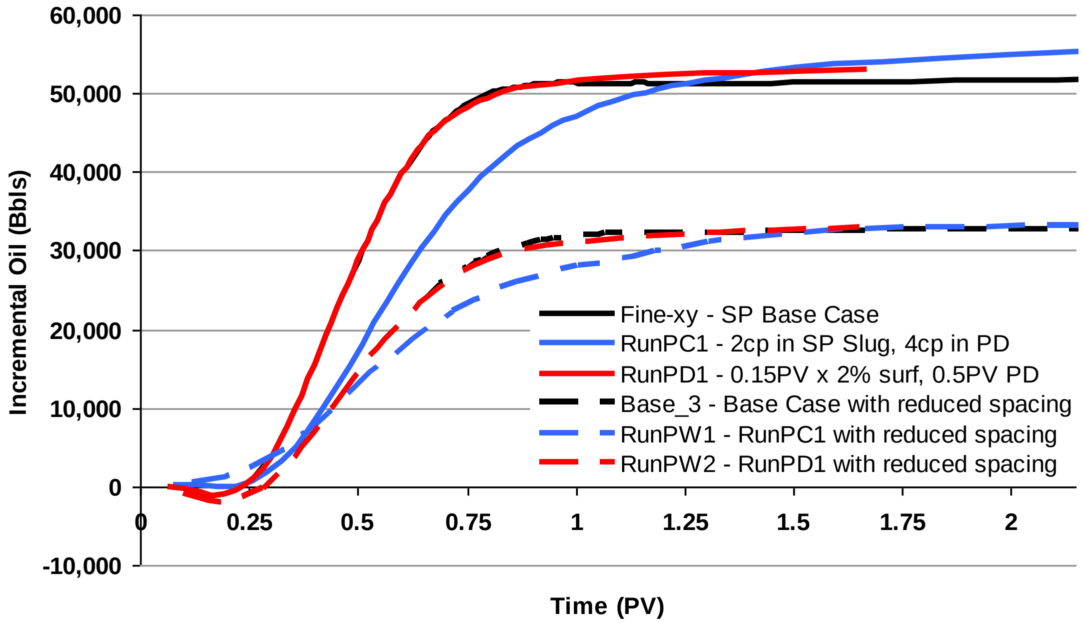

Figure 4-26: Pilot Well Spacing Simulations - Incremental Oil vs. PV Injected

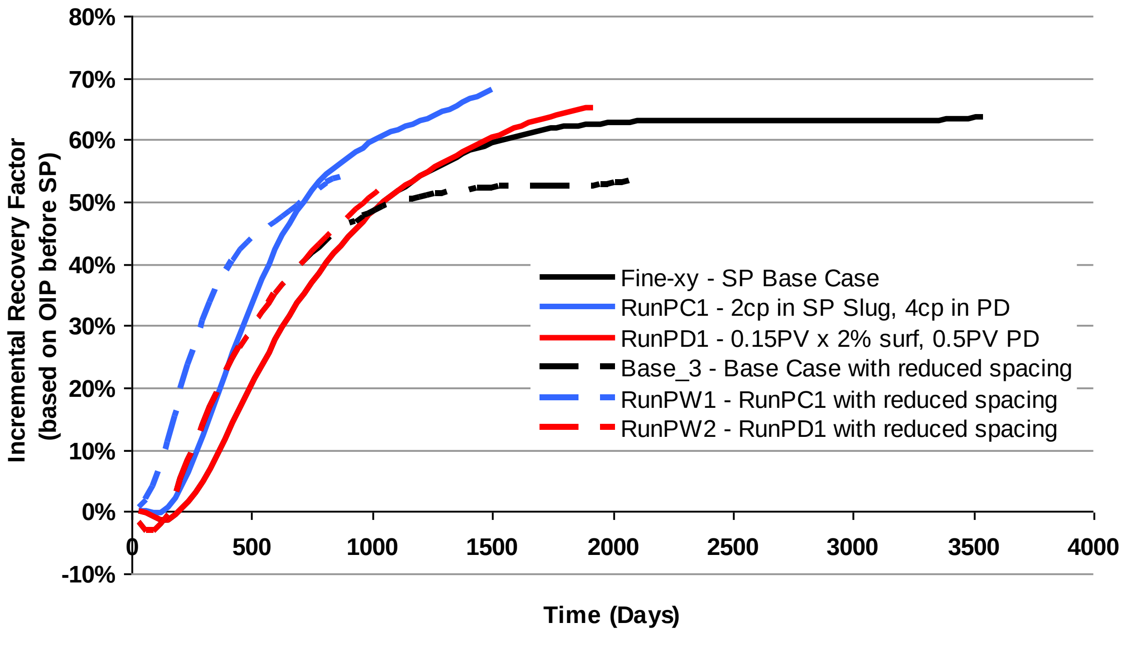

Figure 4-27: Pilot Well Spacing Simulations - Recovery Factor vs. Time

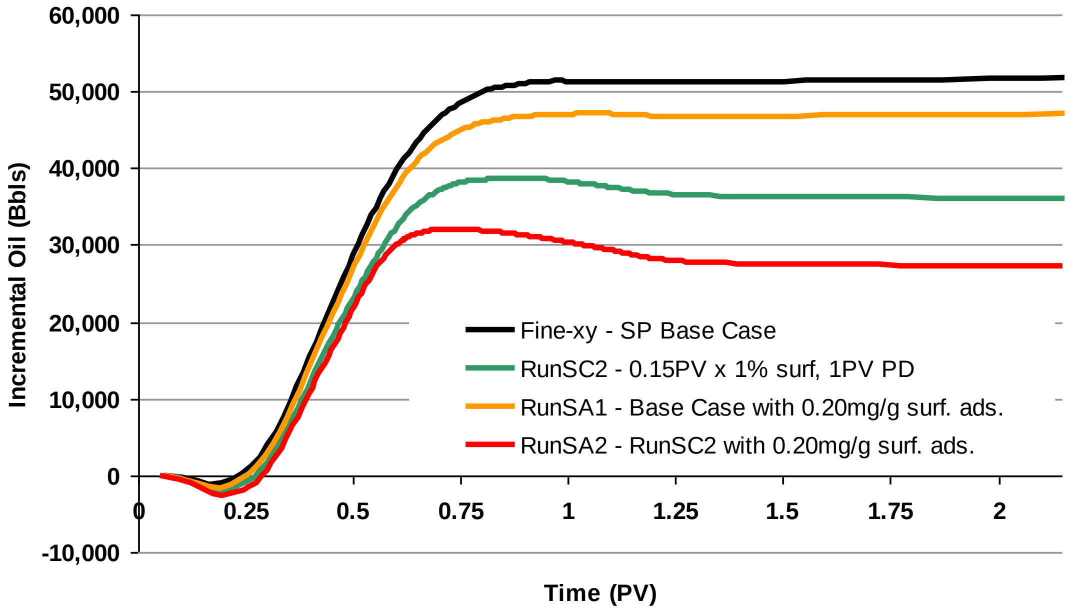

Figure 4-28: Surfactant Adsorption Simulations - Incremental Oil vs. Pore Volumes Injected

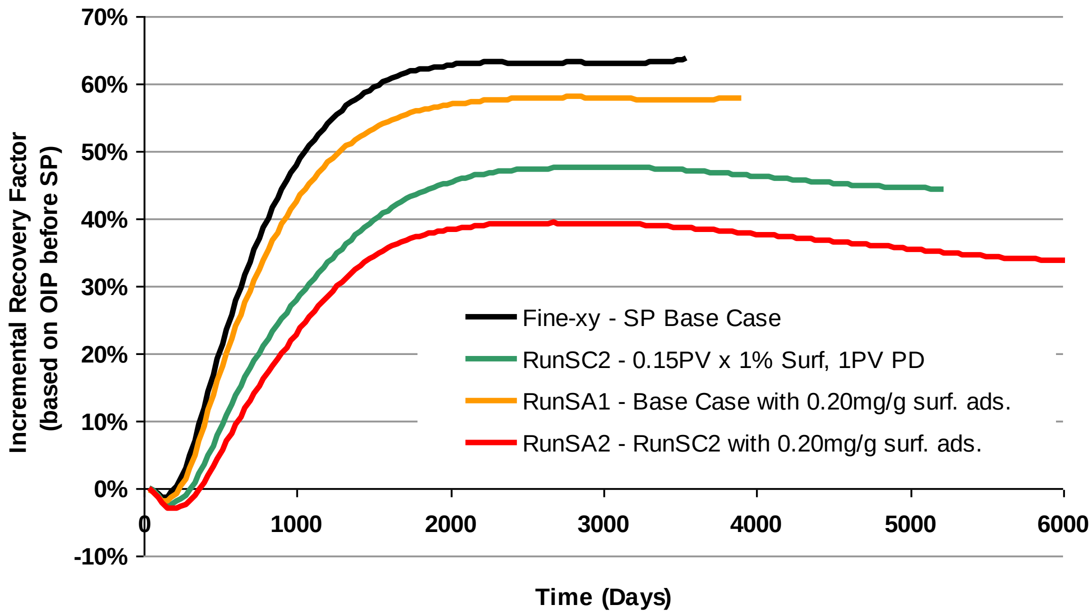

Figure 4-29: Surfactant Adsorption Simulations - Recovery Factor vs. Time

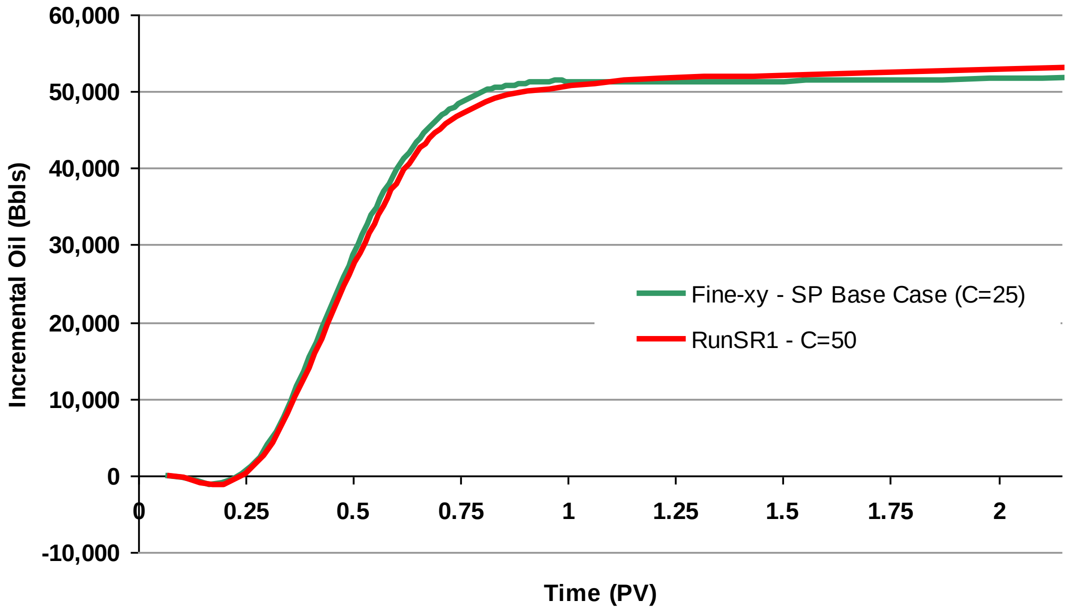

Figure 4-30: Effective Shear Rate Simulation - Incremental Oil vs PV Injected

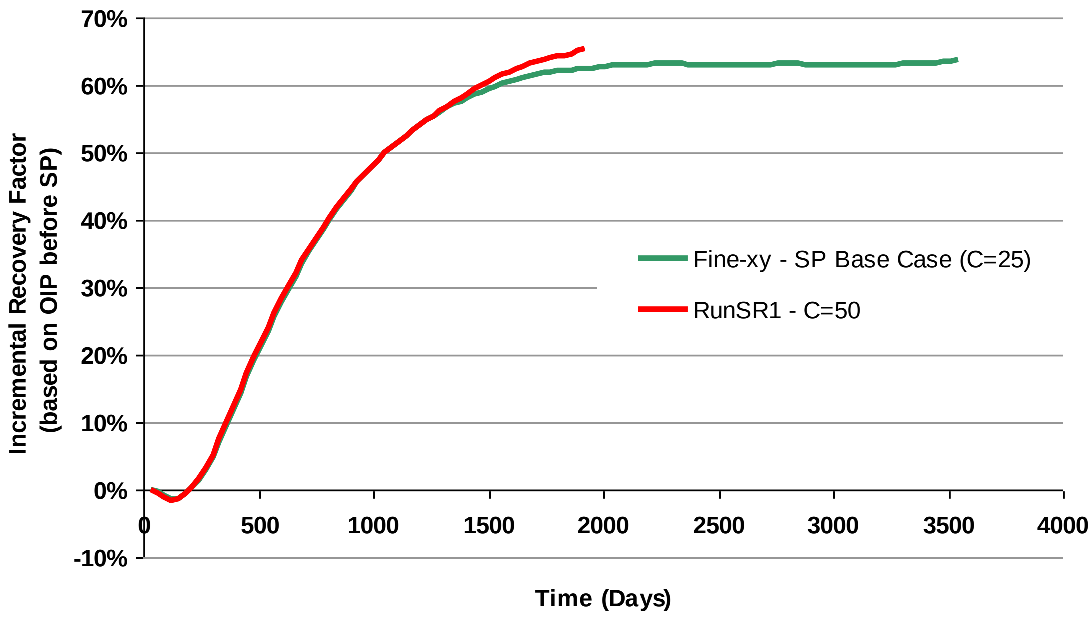

Figure 4-31: Effective Shear Rate Simulation - Recovery Factor vs Time

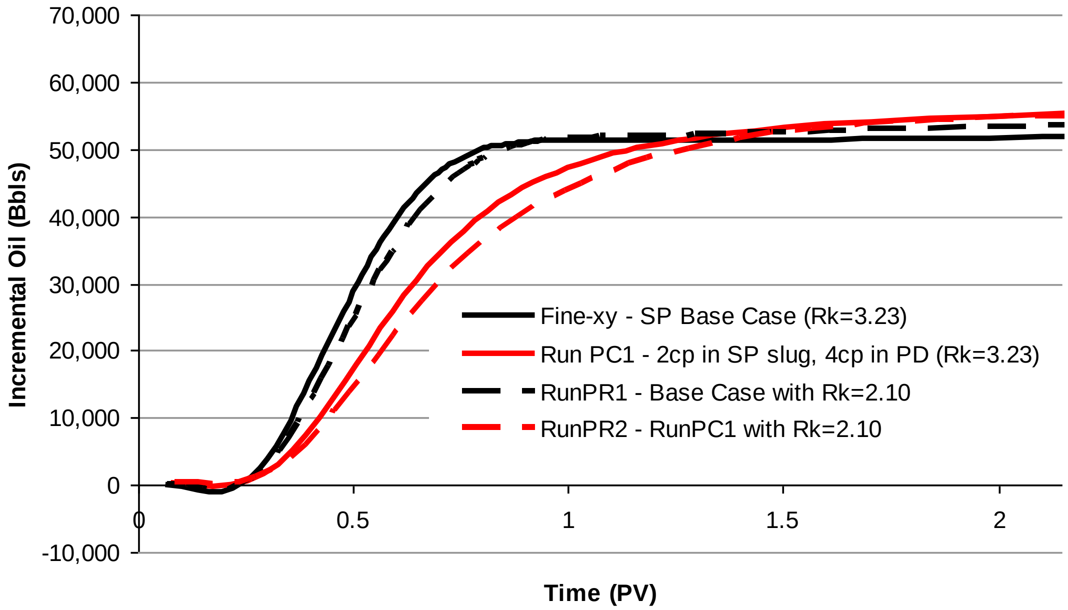

Figure 4-32: Permeability Reduction Simulations - Incremental Oil vs. Pore Volumes Injected

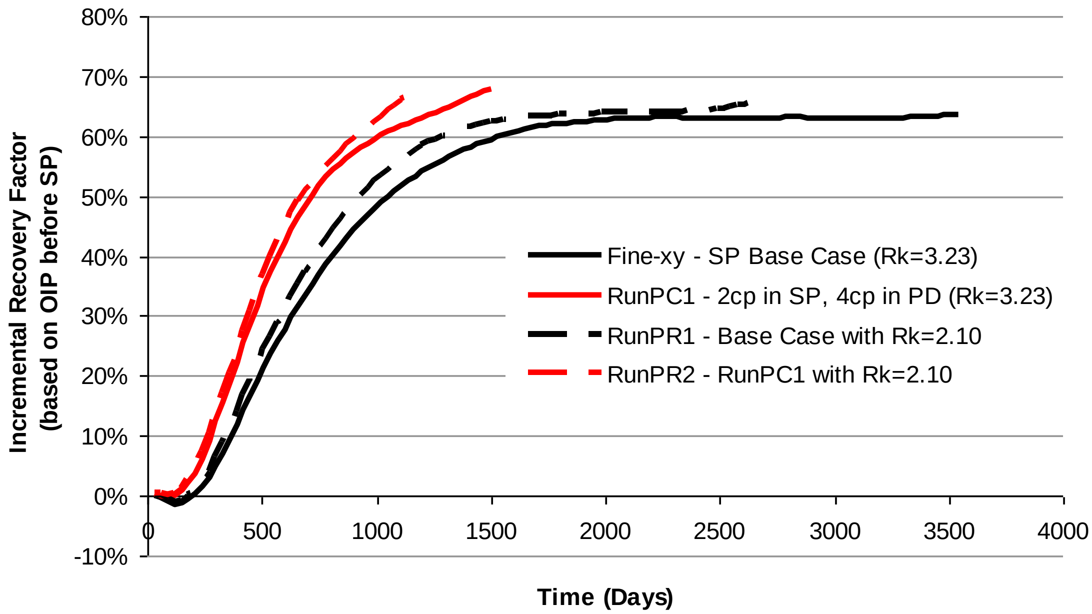

Figure 4-33: Permeability Reduction Simulations - Recovery Factor vs. Time

Table 4-6: Summary of Simulations Performed

Simulation Name	Surfactant Slug Size (PV)	Surfactant Conc. (vol %)	Surfactant Mass (1000lbs)	Polymer Drive Size (PV)	Polymer Concentration (wt %)		Polymer Mass (1000lbs)	Incremental Oil (1000Bbls)	Surfactant Efficiency (lbs/bbl)	Polymer Efficiency (lbs/bbl)	Chemical Cost per Barrel ($/bbl)	Project Life (Years)
					in SP	in PD						
Base Case	0.15	2	189.4	1	0.95	1.1	777.3	51.76	3.66	15.02	33.50	9.7
RunSF1	0.15	2	189.5	-	-	-	-	23.52	8.06	-	24.18	1.0
RunSF2	0.3	1	187.4	-	-	-	-	30.97	6.05	-	18.15	1.0
RunSC1	0.3	1	186.7	1	0.95	1.1	863.4	50.17	3.72	17.21	36.98	10.9
RunSC2	0.15	1	94.4	1	0.95	1.1	773.1	36.11	2.61	21.41	39.95	14.3
RunSC3	0.15	3	281.0	1	0.95	1.1	776.7	54.38	5.17	14.28	36.93	9.0
RunPC1	0.15	2	187.0	1	0.385	0.593	405.8	55.25	3.38	7.35	21.17	4.1
RunPC2	0.15	2	164.8	1	0.226	0.381	161.2	47.23	3.49	3.41	15.59	2.0
Base_2	0.15	2	189.4	0.5	0.95	1.1	432.3	53.05	3.57	8.15	22.93	5.3
RunPD1	0.15	2	139.5	0.5	0.385	0.593	221.2	50.32	2.77	4.40	14.91	2.5
RunPD2	0.15	2	164.8	0.5	0.226	0.381	91.1	40.34	4.08	2.26	15.64	1.5
Base_3	0.15	2	138.9	1	0.95	1.1	575.2	32.52	4.27	17.69	39.35	5.5
RunPW1	0.15	2	138.6	1	0.385	0.593	301.7	33.08	4.19	9.12	26.25	2.4
RunPW2	0.15	2	138.9	0.5	0.95	1.1	320.7	32.78	4.24	9.78	27.38	3.0
RunSA1	0.15	2	187.7	1	0.95	1.1	745.7	47.07	3.99	15.84	35.72	10.7
RunSA2	0.15	1	94.1	1	0.95	1.1	779.6	27.29	3.45	28.56	53.19	17.2
RunSR1	0.15	2	187.3	1	0.95	1.1	779.6	53.21	3.52	14.65	32.54	5.3
RunPR1	0.15	2	187.8	1	0.95	1.1	775.1	53.36	3.52	14.53	32.35	7.3
RunPR2	0.15	2	186.2	1	0.385	0.593	406.0	54.91	3.39	7.39	21.26	3.2

Assumes $3/lb-surfactant and $1.50/lb-polymer

CHAPTER 5 : PILOT-SCALE DESIGN OF AN ALKALINE-SURFACTANT-POLYMER FLOOD

The focus of this chapter will be to optimize the design of an ASP pilot while accounting for alkali consumption due to soap generation, dilution and cation exchange. There will also be studies to investigate the impact of mobility control in the ASP slug and its impact on sweep efficiency.

As part of the injection strategy, the operator decided to pursue a polymer pre-flood early in the project life when oil saturation was still fairly high. The reason for this is that the oil viscosity is approximately 17 cp at the reservoir temperature of 65°C and the oil cut reduces very quickly due to an adverse mobility ratio and heterogeneities. Injecting a polymer solution of 20cp will decrease the end-point mobility ratio from 24 to 0.55.

However, because of the presence of polymer in the reservoir before ASP injection, the apparent viscosity of the oil bank increases significantly compared to an injection strategy without a polymer pre-flood. To calculate the total relative mobility of the oil bank, the water viscosity now has to be replaced by the viscosity of the polymer in the pre-flood. The polymer requirements in the ASP slug will now be considerably higher in order to have a stable displacement process. Simulations will be performed to investigate the impact of the ASP slug mobility on the oil recovery.

5.1 Simulation Model

Properties for the simulation model were provided by the operator and include porosity, permeability, depth, initial water saturation, rock type and relative permeability data. These properties are summarized in Table 5-1 and maps of the permeability and oil saturation are shown in Figure 5-1 - Figure 5-6. Other properties such as fluid viscosities, IFT, brine composition and acid number were obtained from laboratory measurements and are also summarized in Table 5-1.

These figures show lot of variation in gridblock properties both in the x-y plane and also in the vertical direction, thereby highlighting the heterogeneous nature of this reservoir. In order to better understand the impact of these simulations on the oil recovery, oil saturation maps will be plot in Layer 47, which has relatively less heterogeneity than the rest of the layers in this model.

The reservoir is approximately 2500ft deep and contains relatively clean sandstone with low concentrations of kaolinite. On average, the porosity in the pay-zone is 22% and the permeability is 2100md. The pilot area will be flooded with a normal 5-spot pattern (four injectors and one central producer), and will include a waterflood and polymer pre-flood before ASP injection. The average oil saturation inside the pilot area before ASP injection is fairly high at 70%. The ASP slug with then be followed with a polymer slug and water slug. The pattern rates will be balanced, with the total injection and production rates both equaling 1500 BPD. The injector wells are controlled with constant flowrate and the producer was controlled with constant flowing bottom-hole pressure.

5.2 Obtaining Parameters for Field-Scale Simulations

Phase behavior and coreflood experiments were performed at the University of Texas with the chemical formulation listed in Table 5-2. Matching these experiments with UTCHEM would provide most of the parameters used for the field scale simulations. More details of the matching procedure are discussed elsewhere (Anderson, 2006 and Mohammadi, 2008). The matches for surfactant and soap phase behavior, coreflood oil recovery and coreflood surfactant production are shown in Figure 5-7 - Figure 5-11. Finally, the water composition data was converted from parts-per-million notation to equivalents per liter and the measured pH of the brine was matched by using EQBATCH.

5.3 EQUATIONS MODELED IN COREFLOOD AND FIELD-SCALE SIMULATIONS

The comprehensive ASP modeling option in UTCHEM was used for the simulations in this chapter. A brief review of this model is provided by Mohammadi et al (2008) and the UTCHEM Technical Documentation (2011). The reactions modeled for the simulations in this chapter are:

$$HA_o \underset{}{\overset{K_d}{\rightleftarrows}} HA_w \qquad K_d = \frac{[HA_w]_{water}}{[HA_o]_{oil}} \tag{5.1}$$

$$H_2O \overset{K_1^{eq}}{\rightleftarrows} H^+ + OH^- \qquad K_1^{eq} = \left[H^+\right]\left[OH^-\right] \tag{5.2}$$

$$HA_w + OH^- \overset{K_2^{eq}}{\rightleftarrows} A^- + H_2O \qquad K_2^{eq} = \frac{\left[A^-\right]\left[H^+\right]}{[HA_w]} \tag{5.3}$$

$$H^+ + CO_3^{2-} \overset{K_3^{eq}}{\rightleftarrows} HCO_3^- \qquad K_3^{eq} = \frac{\left[HCO_3^-\right]}{\left[H^+\right]\left[CO_3^{2-}\right]} \tag{5.4}$$

$$2H^{+} + CO_3^{2-} \underset{}{\overset{K_4^{eq}}{\rightleftarrows}} H_2CO_3$$

$$K_4^{eq} = \frac{\left[H_2CO_3\right]}{\left[H^{+}\right]^2\left[CO_3^{2-}\right]} \quad 5.5$$

$$\overline{Na}^{+} + H_2O \overset{K_1^{ex}}{\rightleftarrows} \overline{H}^{+} + Na^{+} + OH^{-}$$

$$K_1^{ex} = \frac{\left[Na^{+}\right]\left[\overline{H}^{+}\right]}{\left[\overline{Na}^{+}\right]\left[H^{+}\right]} \quad 5.6$$

Equation 5.1 models the partitioning of the acid in the crude oil to the water phase. Equation 5.3 models the conversion of the acid in the water phase to soap. Equations 5.2, 5.4 and 5.5 model the aqueous reactions of the species that are either in the formation or in the injected fluid. Finally, Equation 5.6 models the ion exchange between the adsorbed sodium and hydrogen ions. This reaction, along with the soap generation reaction, can lead to consumption of the injected alkali.

There are many other reactions that can be tracked such as the dissolution and precipitation of calcium carbonate, the exchange reaction between adsorbed calcium and hydrogen ions and finally the exchange reaction between the adsorbed calcium and adsorbed sodium ions. However, since the concentration of divalent cations in the injected water is very small (<400 ppm in unsoftened brine and <10 ppm in softened brine), these reactions were excluded from the comprehensive model to reduce the computational time.

5.4 Base Case Simulation

Guidelines for the base case injection scheme were provided by the operator based on previous simulations using a different surfactant formulation. The reservoir has undergone 8 months of waterflood and it was projected that this would be followed by 5months of a polymer pre-flood. The ASP injection scheme involved injection of approximately 0.4 PV of ASP slug, 0.4 PV of polymer drive and 0.4 PV of water chase.

The polymer viscosity in the on-going pre-flood is 20 cp. The ASP and Polymer Drive slug concentrations were determined by using the waterflood relative permeability curves to calculate the minimum oil-bank mobility. This procedure has already been discussed in Chapters 3 and 4 and a plot of the total relative mobility is shown in Figure 5-12. More details about the slug sizes and concentrations are provided in Table 5-3 and Table 5-4.

The concentration of alkali in the ASP slug is 3 wt%, which is slightly higher than the optimum salinity of the surfactant. The in-situ Type III effective salinity window is dependent on the molar fraction and the Type III effective salinity window of the surfactant and soap. Therefore, the in-situ Type III salinity window is likely to be lower than the Type III window of surfactant because of the generation of hydrophobic soap with a lower Type III effective salinity. Injecting at slightly higher than the optimum salinity of surfactant will ensure that a normal salinity gradient will be maintained. However, it is important to use the base case simulation to understand the degree of alkali consumption and identify the optimum concentration of alkali that should be injected with the slug.

The results of this simulation are shown in Figure 5-13 and Figure 5-14. The recovery at the end of the water chase is approximately 640,000 bbls. This is approximately 121% of the original oil in place, which implies that oil is being produced from outside the pilot area. Since the mobility ratio in the polymer pre-flood is lower than 1, this will cause the steamlines to bulge outside the pattern before they make their way to the producer. Therefore, since some of the area outside the pilot area is also swept by the chemical slugs, it explains how oil from outside the pilot area is recovered. This is illustrated in the oil saturation map in Figure 5-5.

The results also show that the concentration of surfactant at the producer is still fairly high. This implies that not all the injected surfactant has been produced back.

Therefore, another simulation was performed where the polymer drive size was increased from 0.4 PV to 1.2 PV (15months total). This simulation is referred to as Base_2 and the results are shown in Figure 5-15 and Figure 5-16.

These figures show that more of the surfactant is produced back and the produced concentration at the end of the simulation is lower than the base case. In the base case, 17.3% of the surfactant is produced back, compared to 38.6% in the Base_2 simulation. Not all the surfactant is expected to be produced back due to adsorption on the rock surface. From the produced concentrations, it can be seen that the produced effective salinity decreases more gradually and the Type III region increases. This is because the mobility ratio between the water and polymer is poor and so the water chase fingers through to the producer and does not effectively displace the polymer drive and ASP slugs.

The results of this simulation also highlight the importance of ensuring that the surfactant has been efficiently propagated through the reservoir. An additional 130,000 bbls of oil was recovered after increasing the size of the polymer drive, and the oil saturation in the pilot area at the end of the base case and Base_2 simulations was 45.2% and 39.3% respectively. The oil saturation is still fairly high at the end of the simulation because of the heterogeneous nature of the reservoir. In Layer 47, which has a more evenly distributed permeability field, the final oil saturation in the base case and Base_2 simulations is 17.1% and 14.0% respectively. In light of these results, all subsequent sensitivity simulations will be compared against this updated base case.

5.5 Sensitivity Simulations

This section will highlight some of the simulations that were performed to optimize the salinity gradient and sweep efficiency of the chemical slugs. The first set of simulations will investigate the sensitivity to the alkali concentration in the ASP slug. The second set will look at the impact that adding salt in the preflood and polymer drive slugs will have on the salinity gradient. The third set of simulations will investigate the impact of increasing the polymer viscosity in the ASP and polymer drive slugs to improve the sweep efficiency. The last set of simulations will look at the impact of the cation exchange capacity on the propagation of surfactant, soap and salinity, and the corresponding impact on the cumulative oil recovery.

5.5.1 Alkali Concentration in ASP Slug

The alkali concentration in the base case simulation is 3% and from the graph of the produced salinity it can be seen that the Type III region is achieved. The produced concentration of surfactant and soap in this Type III environment is fairly high which indicates that the low-IFT environment does propagate through the reservoir. Two additional simulations were performed with the concentration of alkali at 2% and 1% respectively. These runs will be referred to as ALKC_2 and ALKC_1 respectively. The purpose behind these simulations was to see if injecting a lower concentration of alkali will still generate a Type III phase behavior environment that travels with the surfactant and soap. Ideally, injecting a lower concentration is more favorable as long as low IFT is still achieved since the polymer requirements will be reduced. However, the injected concentration should be high enough to avoid consumption and dilution effects that can lead to under-optimum conditions.

The results of these two simulations are shown in Figure 5-17 - Figure 5-22. All the simulation results were compared by calculating the difference in cumulative oil that would have been obtained with a polymer flood. In this polymer flood, the chemical concentrations are the same as those in the polymer pre-flood and this slug is injected for 2PV. This polymer slug injection is followed up with 0.4PV of water injection. The simulation results show that the Base_2, ALKC_2 and ALKC_1 simulations yield 69,700 bbls, 45,600 bbls and 40,000 bbls of incremental oil respectively.

The oil saturation maps at the end of each of these simulations show that the amount of residual oil that is mobilized decreases as the concentration of alkali in the ASP Slug is reduced. In fact, in run ALKC_1, oil is only mobilized around the injector and by the time the slug reaches the producer, the salinity is significantly under optimum. Even though only 1% Na_2CO_3 is used in this simulation, the Type III salinity environment is still achieved around the injector at early time because the surfactant mole fraction and alkali consumption is initially low. This means that the effective in-situ salinity has not reduced significantly from the slug salinity, and that the Type III salinity window is closer to the salinity window for soap. However, as this slug propagates though the reservoir, more of this injected alkali gets consumed and starts to lag behind the surfactant front. By the time this alkali front reaches the producer, the salinity is under optimum and it lags behind the surfactant front as shown in Figure 5-19.

It is also interesting to note that the incremental oil recovered is not significantly different between these three simulations. Part of the reason for this is due to the fact that the volume of reservoir swept is different in each of these scenarios. An under-optimum flood may not show significant IFT reduction and will essentially perform similar to a polymer flood. However, since the polymer concentration in the ASP slug and polymer drive is higher than the concentration of the pre-flood, and since there is no significant relative permeability enhancement from the surfactant or soap because of the under-optimum conditions, the mobility ratio between the injected chemical slugs keeps increasing. Similarly, if enough alkali is injected to form in-situ soap and maintain a Type III phase environment, the relative permeability to water and oil will get enhanced. Since the mobility ratio between the ASP slug and the ASP oil-bank is poor in these sets of simulations, the injected fluid will finger its way through to the producer and will not sweep as much volume as the under-optimum slug. This is illustrated in the oil saturation maps provided in Figure 5-20 - Figure 5-22 where the under-optimum slug shows more of a reduction in oil saturation away from the pilot area.

This reservoir is an example of a relatively unconventional application of ASP flooding as a secondary flood and not a tertiary since the oil saturation is still very high before the chemical flood, especially outside the pilot area. As a result, the oil recovery is still fairly high even when the salinity is under-optimum. A significant difference was observed when comparing the final oil saturation in the pilot area. The final oil saturation in Layer 47 inside the pilot area is 17.1% for the Base_2 run, 17.6% for the ALKC_2 run and 26.6% for the ALKC_1 run. The final oil saturation in the entire pilot area is 39.3% for the Base_2 run, 40.9% for the ALKC_2 run and 41.9% for the ALKC_1 run. This is also an interesting result because while a big difference was seen between the ALKC_2 and ALKC_1 runs in Layer 47, very little difference was seen in the average oil saturation in the entire pilot area. Again, this highlights how the under-optimum simulation is sweeping more reservoir volume than the ALKC_1 and Base_2 simulations. So even though the slugs in the ALKC_1 simulation are not mobilizing as much residual oil, they improved sweep efficiency in this simulation means that it is recovering more mobile oil outside the pilot area than the other two simulations.

In most conventional applications of ASP flooding, the initial oil saturation before flooding is fairly close to the residual saturation to waterflood, and so injecting an ASP slug that is under-optimum will yield very unfavorable results. While these observations are interesting, it is important to perform these simulations on a fine-scale grid to confirm these results. It has already been shown in Chapter 4 and in work by Veedu (2010) how the use of coarse simulation grids to model surfactant processes can lead to under-prediction of oil recovery due to dispersion and artificial dilution of the surfactant.

5.5.2 Salt Concentration in Polymer Drive

In this section, simulations were performed where either 1% of Na_2CO_3 or 1% of NaCl was added to the first five months of the polymer drive, and the corresponding impact on the salinity gradient was analyzed. This extra mass of salt was only added for 5months in order to ensure that the salinity environment goes down to the Type I region. In order to maintain the same viscosity in the Polymer Drive, the polymer concentration in the first 5months of the drive had to be increased from the base case concentration of 1300ppm to 4100ppm. In the first simulation, referred to as ALKC_4, the ASP slug consisted of 3% Na_2CO_3 (same as the Base_2 simulation) and in the second simulation, referred to as ALKC_5, the ASP slug consisted of 2% Na_2CO_3 (same as run ALKC_2). The size and composition of the polymer drive is the same in both these simulations, with 1% of Na_2CO_3 added to the first five months of the polymer drive. The results of these simulations are shown in Figure 5-23.

The results show a significant improvement in recovery when 1% of Na_2CO_3 is added to five months of the polymer drive. The difference in recovery between the Base_2 simulation and ALKC_4 is approximately 57,000 bbls, and the difference between ALKC_1 and ALKC_5 is 58,000 bbls. The results of ALKC_4 also show that with the same amount of alkali and the same slug viscosities as the Base_2 simulation, the cumulative recovery increases by 34,000 bbls. The oil saturation in the pilot area also reduces considerably. The average oil saturation at the end of the water chase is 39.3% is the base case and 36.0% in the simulation ALKC_4. The oil saturation also reduces from 40.9% in ALKC_2 to 37.2% in ALKC_5.

To investigate the impact of using sodium chloride instead of sodium hydroxide for the purpose of managing the salinity gradient, a simulation similar to ALKC_4 was performed. The difference was that 1% of NaCl was used in place of 1% Na_2CO_3 in the polymer drive, and the polymer concentration had to be adjusted to maintain the same viscosities as ALKC_4. The simulation is referred to as NACL_1 and results are shown in Figure 5-26 and Figure 5-27. The results show that there is very little difference in the incremental oil and the salinity profile between these two simulations.

5.5.3 Salt Concentration in Polymer Pre-flood

The option of injecting salt in the polymer pre-flood to manage the salinity gradient was also investigated. In NACL_2, 1% of sodium chloride was added to the polymer pre-flood and the polymer concentration was increased to keep the slug viscosity at 20cp (this is the same pre-flood slug viscosity as the Base_2 simulation). The results are shown in Figure 5-28 and Figure 5-29.

The results show that an additional 10,900 bbls of oil that are recovered over the base case. While this simulation does show more recovery than the base case, the results indicate that adding the extra salt in the polymer drive is more favorable. Since the surfactant and soap fronts get retarded due to adsorption and consumption, the extra salt that is added to the Pre-flood increases the salinity ahead of the surfactant. This is illustrated when comparing the produced salinity, surfactant and soap profiles of the NACL_2 and NACL_1 simulations. Ideally, the optimum salinity should be achieved in the presence of the injected surfactant and soap.

5.5.4 Sensitivity to Cation Exchange Capacity

The operator provided rock composition data that was obtained through x-ray diffraction. On average, the reservoir rock contains mostly quartz and kaolinite, at 83% and 8% respectively. Illite, Mica and Chlorite composed of 0.2%, 1.4% and 1% of the rock respectively. The remainder of the rock was made up of other trace minerals. Since several rock samples were available, the cation exchange capacity (CEC) was calculated for each sample by taking the weighted average of the fundamental exchange capacity values for each of the clay minerals. It was assumed that the fundamental values for kaolinite, illite and smectite were 10 eq/100g-rock, 40 eq/100g-rock and 40 eq/100g-rock. For each rock sample, the weighted average CEC was calculated and converted into meq/ml-PV units for UTCHEM using the formula

$$Q_v = \overline{Q_v}\rho_{rock}\left(\frac{1-\phi}{\phi}\right) \qquad 5.7$$

Where,

Q_v = Cation Exchange Capacity (meq/ml-PV)

$\overline{Q_v}$ = Cation Exchange Capacity (eq/100g-rock)

ρ = Rock Density (g/cc)

ϕ = Porosity

The CEC varied depending on the rock sample, but the average value was approximately 0.07 meq/ml-PV. There were a few samples that showed values as high as 0.25 meq/ml-PV but majority of the samples were below 0.1 meq/ml-PV. A conservative value of 0.1 meq/ml-PV was chosen for all the simulations performed up to this point. The Base_2 and ALKC_2 simulations were repeated using a CEC of 0.15meq/ml-PV, and were referred to as CEC_3 and CEC_2 respectively. The results are shown in Figure 5-30.

The results show that an increase in the CEC does reduce the incremental recovery for both sets of simulations. Run CEC_3 and CEC_2 recover an incremental 56,300 bbls and 28,400 bbls respectively over polymer flood, whereas the incremental recovery for the Base_2 and ALKC_2 simulations was 69,700 bbls and 45,600 bbls. The difference in incremental recovery between the CEC_3 and Base_2 simulation is 13,400 bbls. The difference in incremental recovery between the CEC_2 and ALKC_2 simulations is 17,200 bbls. This shows that the injection scenario with 2% Na_2CO_3 is slightly more sensitive to the increase in CEC since a larger fraction of the injected alkali in these two scenarios (CEC_2 and ALKC_2) will get consumed by ion exchange.

Simulation run ALKC_4 (3% Na_2CO_3 in ASP slug, 1% Na_2CO_3 in polymer drive) was also repeated using a CEC of 0.15 meq/ml-PV. This simulation run was referred to as CEC_4 and the results are shown in Figure 5-31. The difference in recovery between these two simulations is 10,500 bbls. This sensitivity of this injection scenario to the CEC is even less than the simulation runs where no additional alkali was injected in the polymer drive.

5.6 Polymer Viscosity in the ASP and Polymer Drive Slugs

As discussed previously, the reservoir is being pre-flooded with a 20 cp polymer solution before starting the ASP injection. Two oil banks will develop; one due to the polymer pre-flood and one due to the ASP slug. The polymer viscosity in the ASP slug for the base case simulation was determined by calculating the minimum mobility of the oil-bank, using the waterflood relative permeability curves and the oil and water viscosity at reservoir temperature. However, because the reservoir has been pre-flooded with polymer, the oil-bank due to the ASP will now have polymer in it, and its mobility will now be reduced. To calculate the new minimum mobility, the water viscosity needs to be replaced with the polymer viscosity. This calculation assumes that the relative permeability curves do not change from the polymer flood. As discussed earlier, taking the inverse of this new minimum mobility will provide the polymer requirement for the ASP slug. This is illustrated in Figure 5-32.

It can be seen that the polymer requirement increases very significantly and approximately 110cp is now required in the ASP slug for a stable displacement. The first simulation performed in this section, referred to as Base_3, will have the same slug sizes, surfactant concentration and alkali concentration as the Base_2 simulation. The polymer concentration was increased to 6800 ppm in the ASP slug and 230 ppm in the polymer drive. This will correspond to a viscosity of 100 cp in the ASP slug and 110 cp in the polymer drive. The results are shown in Figure 5-33.

The plot of cumulative oil recovery shows that an additional 84,100 bbls of oil is recovered as a result of the improved sweep efficiency. The oil saturation in the pilot area at the end of the waterflood was 39.3% for the Base_2 simulation and 36.3% for the Base_3 simulation. The oil saturation in Layer 47 in the pilot area reduced from 17.1% in the Base_2 simulation to 11.9% in the Base_3 simulation. This is also illustrated in Figure 5-34, which shows a map of the oil saturation at the end of the Base_2 and Base_3 simulations. This figure shows that the sweep both inside and outside the pilot area has improved when compared to the base case simulation.

Similarly, a simulation was performed using 2% Na_2CO_3 in the ASP slug. The slug viscosities are the same as the Base_3 simulation. The results show that 84,600 bbls of additional oil is recovered over the ALKC_2 simulation (2% Na_2CO_3 with base case slug viscosities).

It can be seen that the produced salinity for the Base_3 case is lower than the produced salinity in the Base_2 simulation. Similar observations were seen when comparing the produced salinity in the ALKC_2 and PV_2 simulations (Both these runs have 2% Na_2CO_3 in the ASP Slug). An additional simulation was performed to investigate the impact of adding 1% Na_2CO_3 in the first 0.4PV of the polymer drive, while keeping the remaining slug sizes and viscosities the same as the Base_3 simulation. The results in Figure 5-37 show that an additional 50,400 bbls was recovered over the Base_3 simulation. Also, from the plot of the salinity gradient in Figure 5-38, it can be seen that the effective salinity is closer to the optimum salinity when the surfactant and soap concentration is high.

Figure 5-39 shows a map of the oil saturation in Layer 47 at the end of the Base_3 and PV_3 simulations. The final oil saturation in this layer was 11.9% in the Base_3 simulation and 5.5% in PV_3 simulation. The oil saturation in the entire pilot area decreases from 36.3% in the Base_3 simulation to 33.9% in the PV_3 simulation. These results show a significant increase in recovery when compared to the set of simulations with lower ASP and polymer drive slug viscosities. Furthermore, they highlight the importance of mobility control and the salinity gradient on maximizing the oil recovery.

5.7 CONCLUSIONS

The goal of this chapter was to investigate the impact of alkali consumption and fluid mobility on a design of an Alkaline-Surfactant-Polymer Pilot in a heterogeneous, sandstone reservoir with a moderately viscous and very reactive oil. The comprehensive ASP modeling option in UTCHEM was used to track alkali consumption due to soap generation reactions, cation exchange and dilution. Alkali consumption will affect the propagation of the surfactant, soap, pH and salinity through the reservoir and the goal of this study was to identify a slug design that will minimize this effect.

The oil saturation in the pilot area before ASP injection is very high at 70% and it was observed that this leads to oil recovery from a more than one mechanism. In a conventional tertiary flood, the oil cut is typically very low at around 1-2%. As a result, if an ASP slug is injected at under-optimum salinity, the project will perform very poorly because it will not successfully mobilize the residual oil. In this study, however, since the mobile oil saturation is very high before ASP injection, the flood will still recover significant oil even if the low-IFT Type III region is not achieved. This is because the under-optimum slug will now work more like a polymer flood. Also, because the polymer viscosity increases from the polymer pre-flood to the ASP slug to the polymer drive, the mobility ratio between these slugs will also increase. This is assuming that there is no enhancement of the relative permeability which is normally achieved under low IFT conditions.

Therefore, an ASP slug that is injected at optimum salinity will recover oil by sweeping both the mobile oil and residual oil. An ASP slug that is injected at under-optimum conditions will sweep the mobile oil only, but because of the increasing mobility ratio, the volume swept by this slug will be greater than the volume swept by the ASP slug that is injected at optimum salinity. With that said, it should be noted that it is important to perform some of these simulations on a fine-scale grid to better quantify the amount of mobile oil recovered. It has been shown by Veedu (2010) how surfactants can smear and become diluted with coarse grids, which can then lead to the surfactant propagating below the critical micelle concentration and/or the effective salinity propagating at under-optimum conditions. In these simulations, it was shown that injecting 3% of Na_2CO_3 will recover 30,000 bbls more oil than injecting at an under-optimum salinity of 1% Na_2CO_3.

It was also demonstrated how injecting 1% of Na_2CO_3 in the first five months of the polymer drive can lead to a more favorable salinity gradient. An additional 57,000 bbls of oil is recovered over the base case simulation when the extra 1% of Na_2CO_3 is added to the polymer drive. It was also demonstrated how injecting at 2% of Na_2CO_3 in the ASP slug and adding 1% Na_2CO_3 in the first five months of the polymer drive will recover more oil and is less sensitive to changes in the alkali consumption and pH loss due to cation exchange than injecting a 3% Na_2CO_3 ASP slug with no added sodium carbonate in the polymer drive.

Finally, the impact of good mobility control in the flood was also demonstrated here. Since the reservoir was preflooded with a 20 cp polymer solution, the oil-bank due to the ASP flood will have a lower mobility than if the reservoir had been waterflooded only. This means that the polymer requirements in the ASP and polymer drive slugs will increase in order to have a stable displacement process. When the polymer concentration in the ASP and Polymer Drive slugs were increased, and all other concentrations and slug sizes were kept the same, the oil recovery increased by 84,100 bbls. When this increase in polymer viscosity was combined with the improved salinity gradient design discussed in the previous paragraph, the incremental oil recovery over polymer flood is almost 205,000 bbls.

Table 5-5 and Table 5-6 provide a description of the simulations performed in this chapter along with the chemical efficiency of each of these scenarios. It can be seen from these results that the scenario with 3% Na_2CO_3 in the ASP slug and 1% Na_2CO_3 in the polymer drive shows the best results compared to the other injection strategies. This scenario is also the least sensitive to an increase in the cation exchange capacity. The importance of good mobility control is also highlighted in this table. The chemical cost per barrel is very favorable for the scenarios with higher polymer viscosity and also shows less sensitivity to changes in the concentrations of chemicals injected.

Table 5-1: Simulation Model Properties

Model Size	689ft x 590ft x 246ft
Grid size	32.8ft x 32.8t x 3.28ft
Average Porosity	22%
Average Permeability	2100md
k_v/k_h	1
Initial Oil Saturation	96%
Oil Saturation (before ASP)	69.9%
Reservoir Depth	2500ft
Pore Volume (in pilot area)	542,330 bbls
Oil In Place (in pilot area)	529,000 bbls
Reservoir Temperature	65°C
Water/Oil Relative Permeability	$S_{orw} = 0.20$; $S_{wrw}= 0.04$ $k_{ro}° = 0.93$; $k_{rw}°= 0.6$ $e_o = 4$; $e_w= 2.36$
Water Viscosity	0.48 cp
Oil Viscosity	17 cp
Formation Brine	Total Anion = 0.1174 meq/ml Total Divalent Cation = 0.0339 meq/ml
IFT	14 dynes/cm
Acid Number	0.5 mg-KOH/g-oil

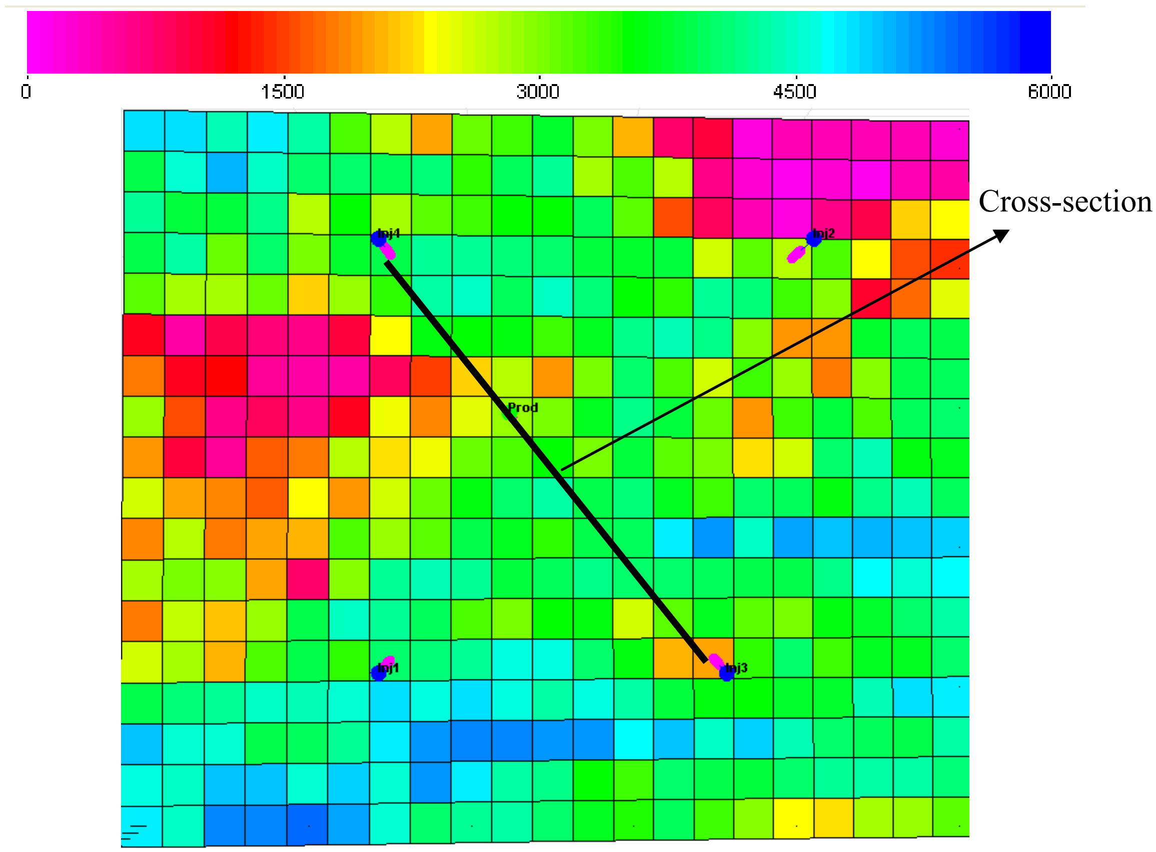

Figure 5-1: Permeability in Layer 47 of Simulation Model

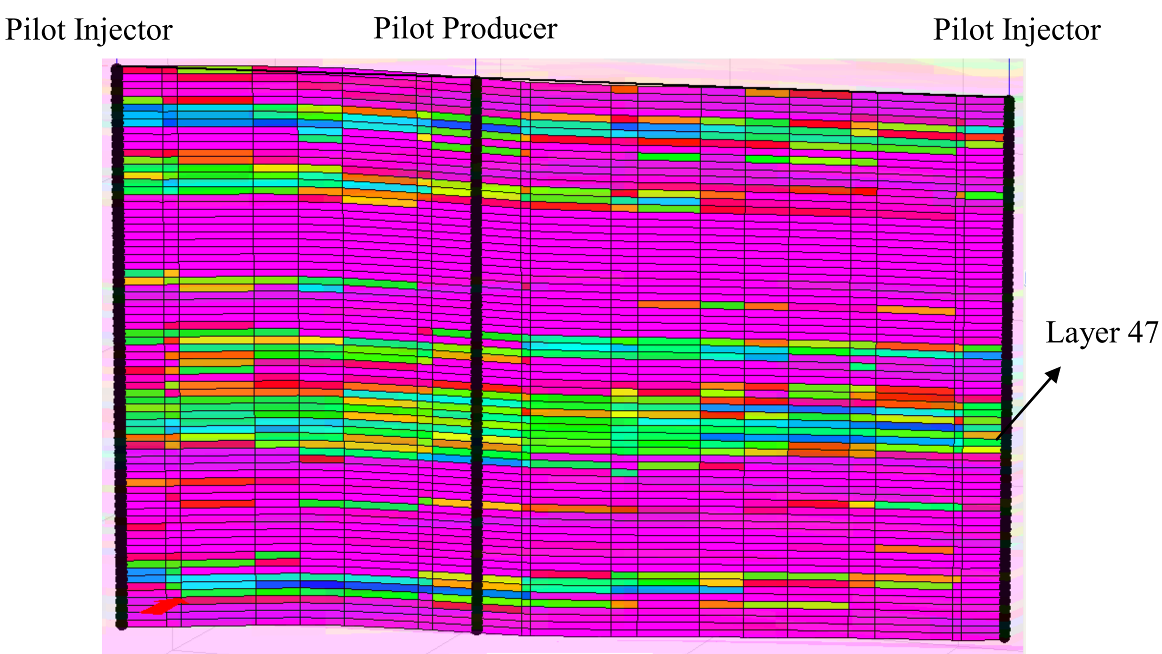

Figure 5-2: Permeability cross-section between Pilot Wells

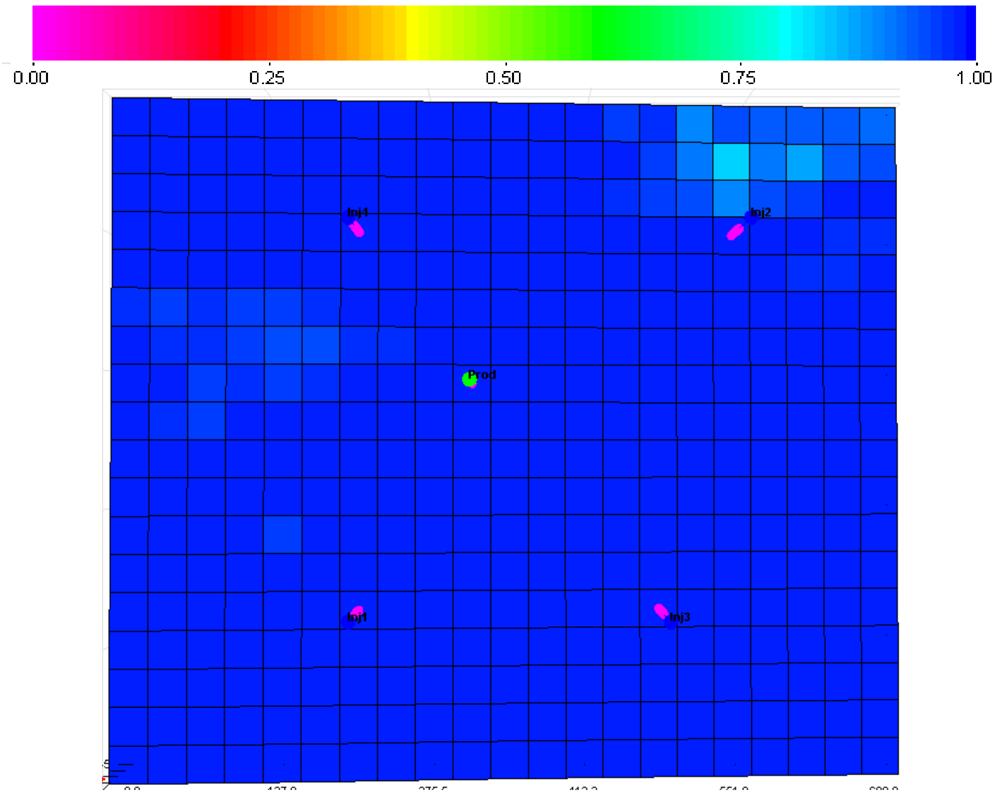

Figure 5-3: Initial Oil Saturation - Layer 47

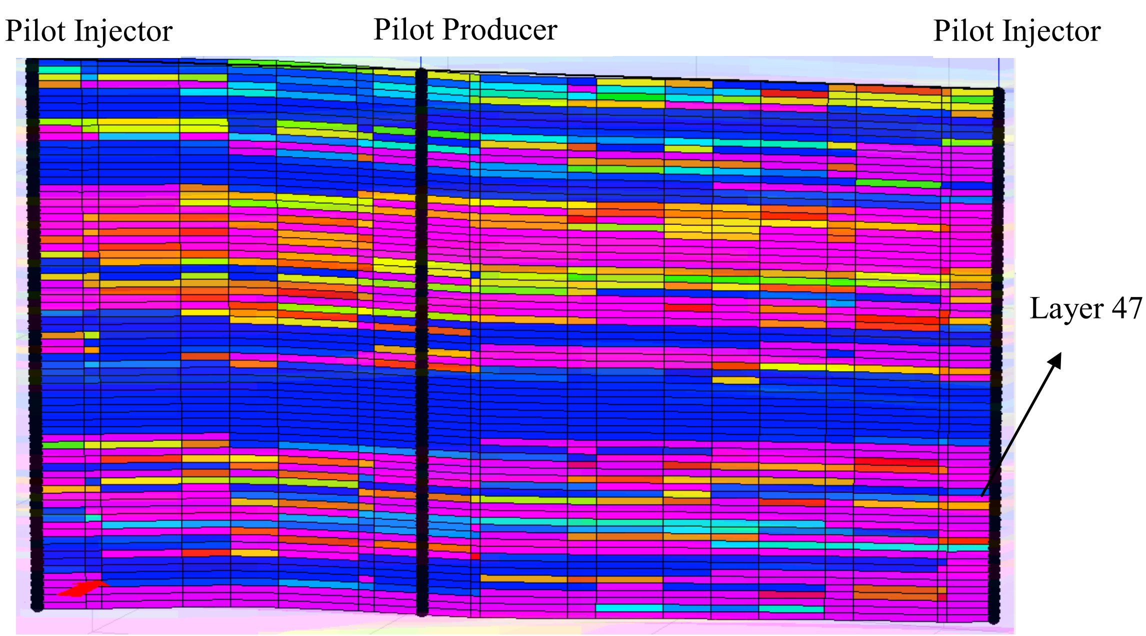

Figure 5-4: Initial Oil Saturation - Cross Section

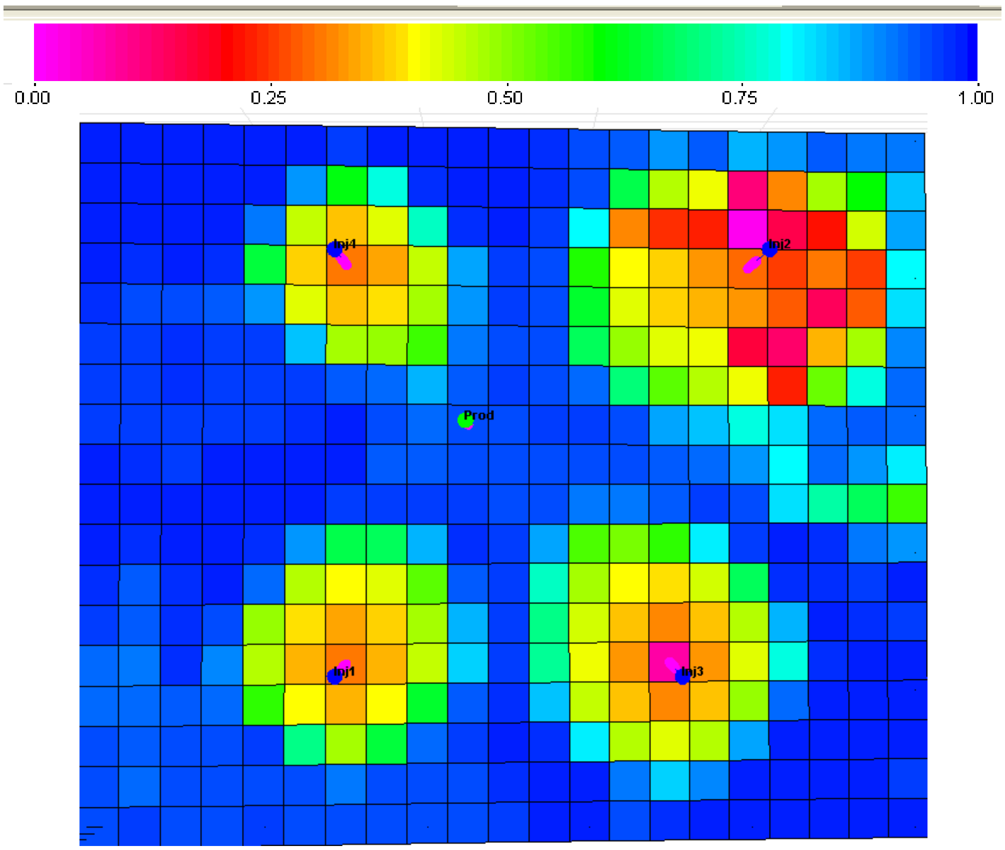

Figure 5-5: Oil Saturation After Polymer Preflood - Layer 47

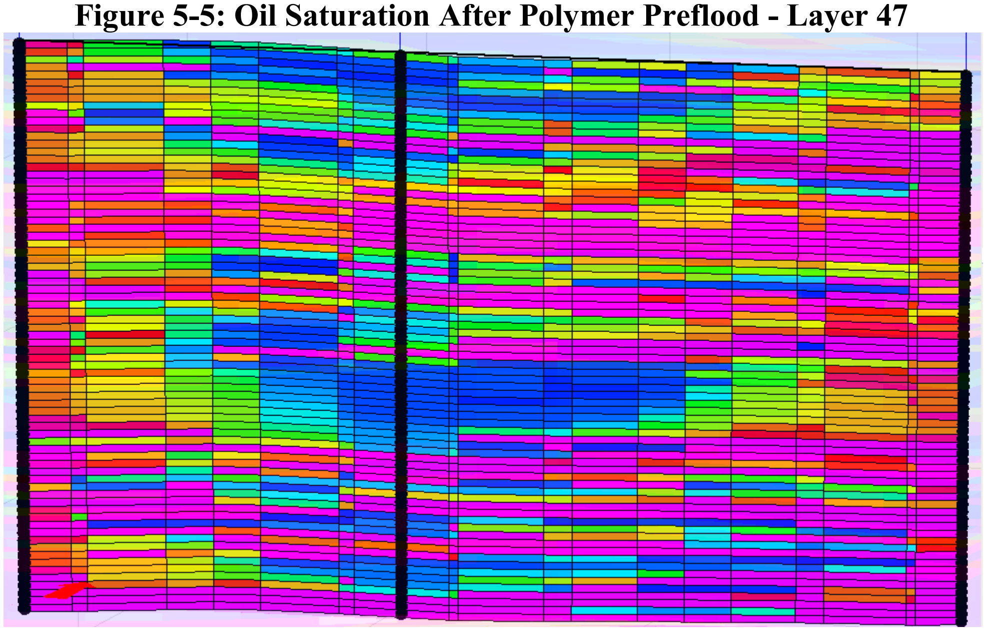

Figure 5-6: Oil Saturation After Polymer Preflood - Cross-Section

Table 5-2: Coreflood Data

Surfactant Slug	0.3 PV 0.18 TSP-35PO-20EO Sulfate 0.12% Petrostep S3B 2.5% Na_2CO_3 3000ppm FP3630
Polymer Drive	1.7 PV 2500 ppm FP3630
Hand's Rule Parameters - Surfactant	HBNC70: 0.080 HBNC71: 0.025 HBNC72: 0.080
Salinity Window - Surfactant	CSEU: 0.60 meq/ml CSEL: 0.30 meq/ml
Hand's Rule Parameters - Soap	HBNC70: 0.080 HBNC71: 0.025 HBNC72: 0.080
Salinity Window - Soap	CSEU: 0.30 meq/ml CSEL: 0.10 meq/ml
Surfactant Adsorption	0.075 mg/g-rock
Polymer Adsorption	12 μg/g-rock
Microemulsion Viscosity	17.5 cp
Relative Permeability (at Low Capillary Number)	$S_{orw} = 0.31$; $S_{wrw}= 0.23$ $k_{ro}° = 0.76$; $k_{rw}°= 0.20$ $e_o = 1.5$; $e_w= 3$
Relative Permeability Parameters (at High Capillary Number)	$S_{orw} = 0.02$; $S_{wrw}= 0.001$ $k_{ro}° =1$; $k_{rw}°= 1$ $e_o = 1$; $e_w = 1$

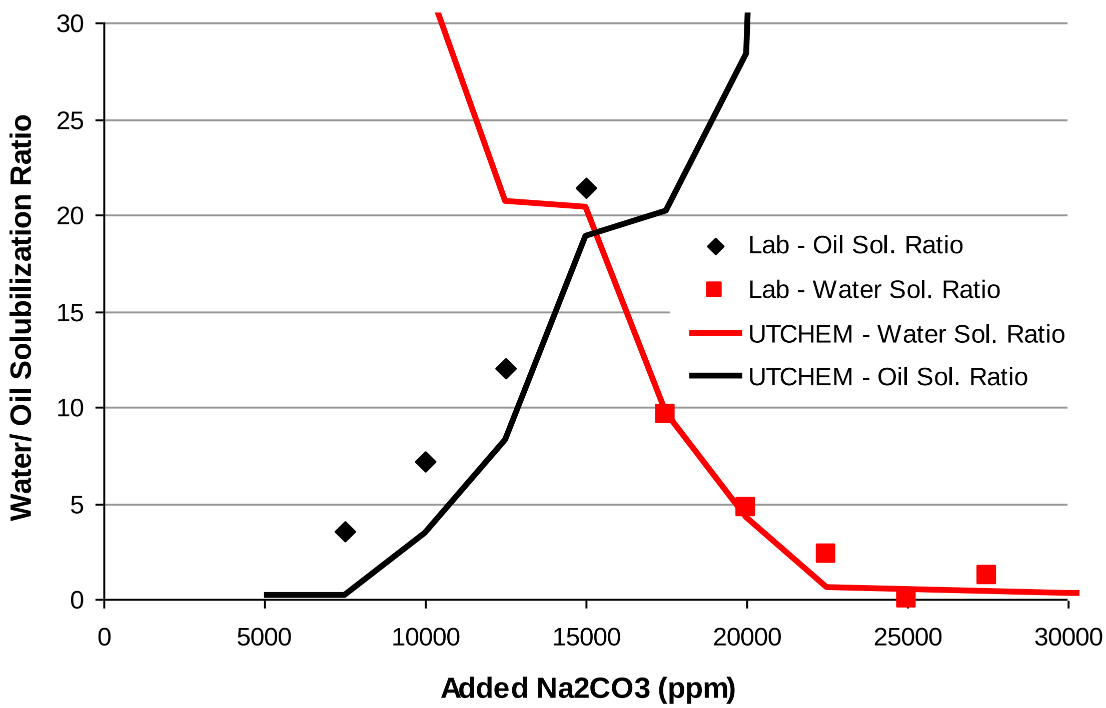

Figure 5-7: Phase Behavior Match - 30% Oil

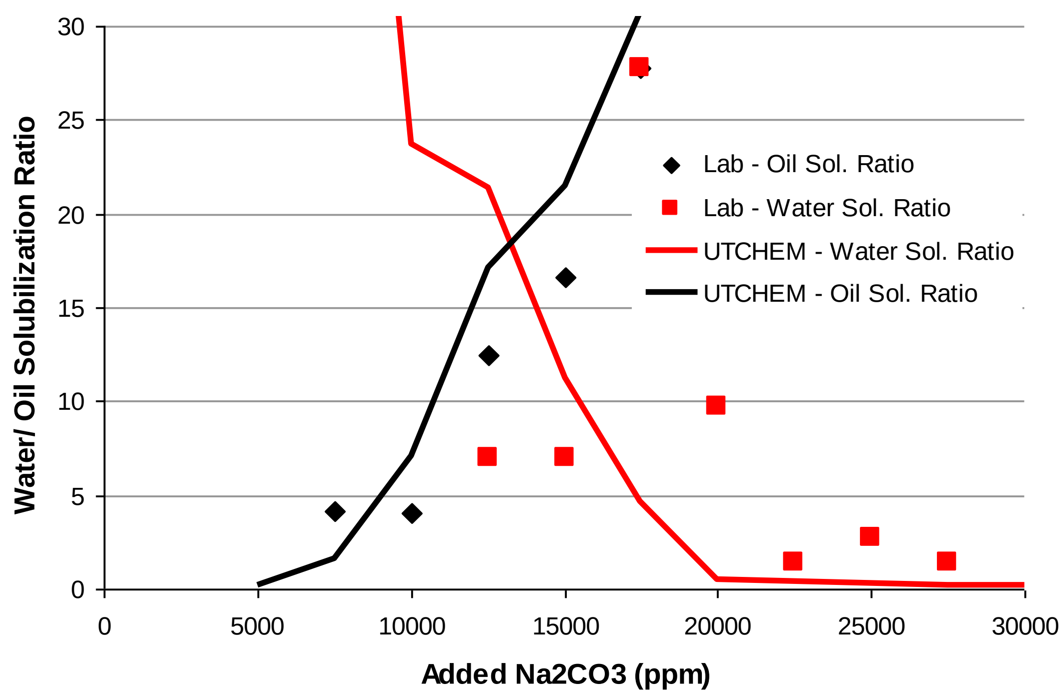

Figure 5-8: Phase Behavior Match - 40% Oil

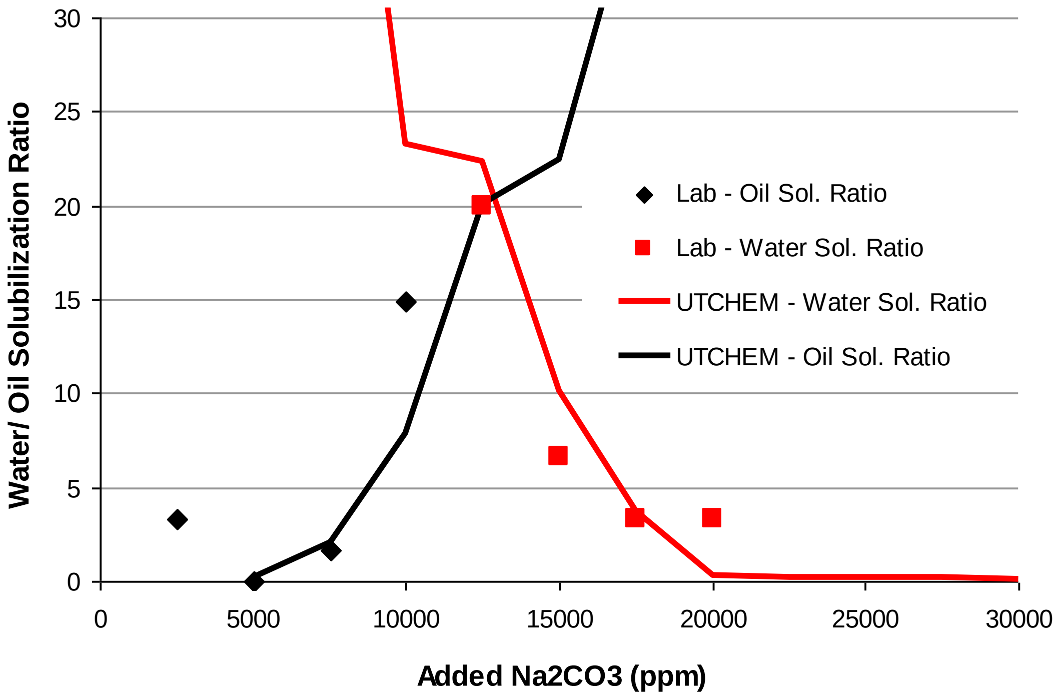

Figure 5-9: Phase Behavior Match - 50% Oil

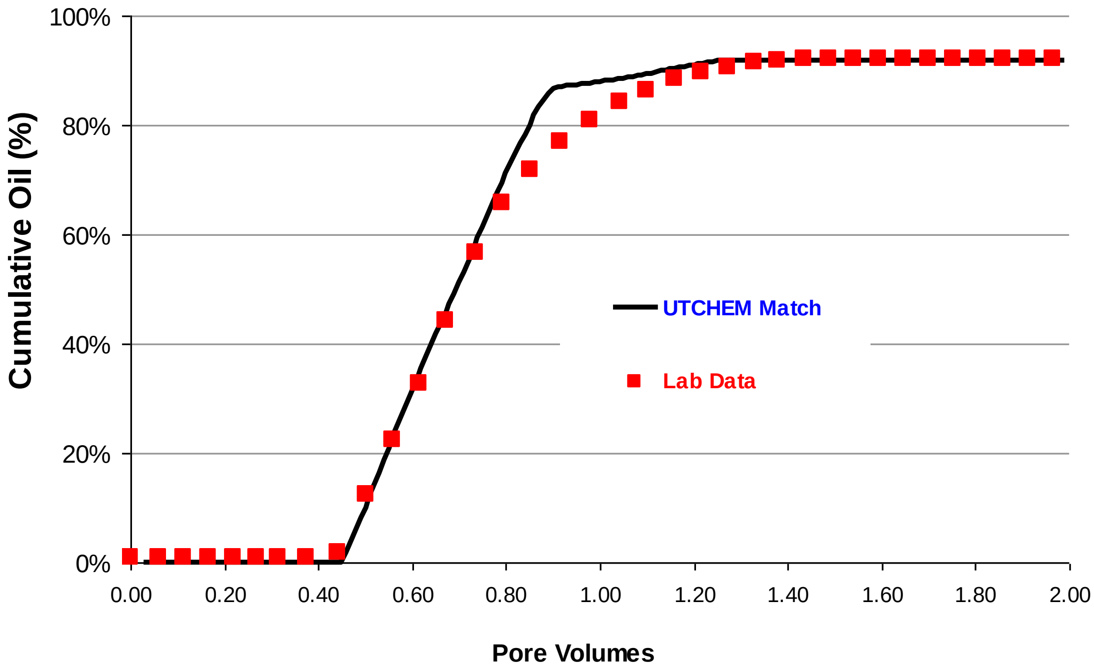

Figure 5-10: Coreflood Match - Cumulative Oil Recovered

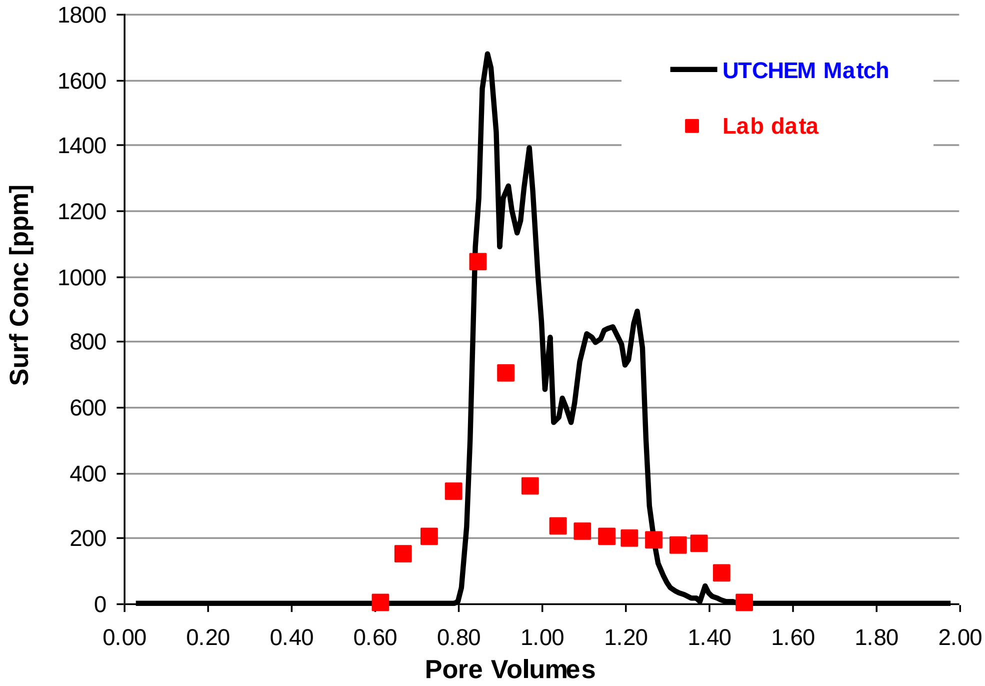

Figure 5-11: Coreflood Match - Surfactant Production

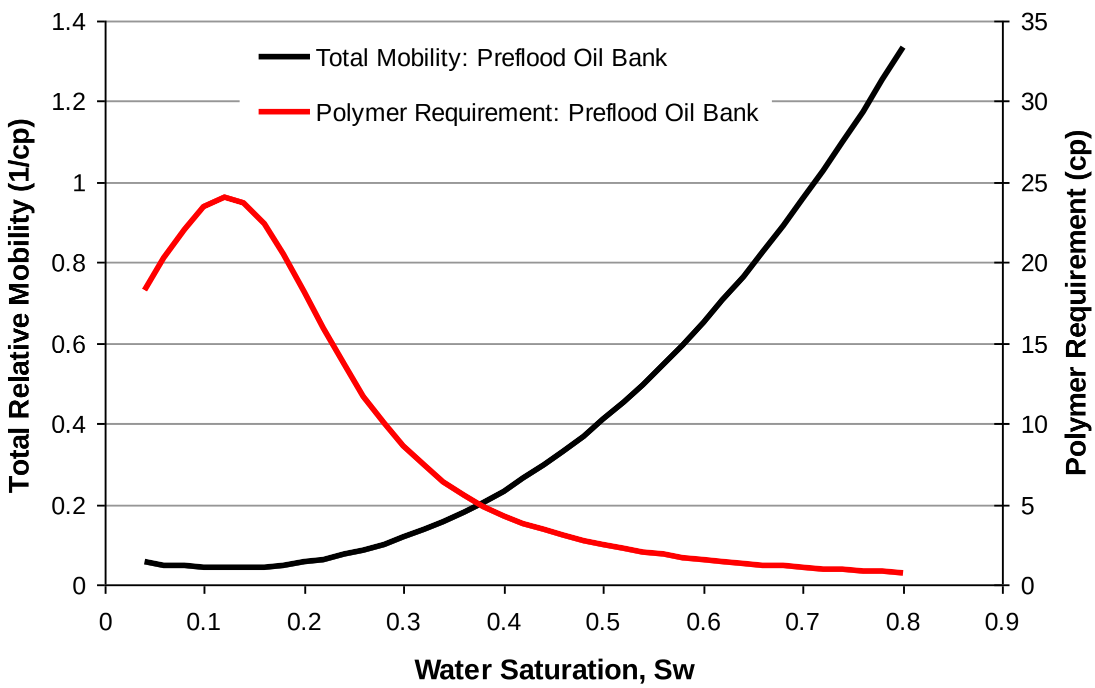

Figure 5-12: Total Relative Mobility - Preflood Oil Bank

Table 5-3: Composition of Formation and Injected Brine

Concentration (ppm)			
	Formation Water	Unsoftened Injection Brine	Softened Injection Brine
Anions			
Cl^-	4160	2620	58.8
SO_4^{2-}	8.5	510	0
HCO_3^-	867.2	265	0
CO_3^{2-}	0.2	0	0
Divalent Cations			
Mg^{2+}	87	120	0
Ca^{2+}	525	237	7.8
SR^{2+}	2.8	10	0
Ba^{2+}	30	10	0
Other Cations			
Na^+	2430	1490	29.13
K^+	190	11	0

Table 5-4: Slug Composition for Base Case Simulation

Injection Rate	375BPD per injector
Waterflood	8 months Unsoftened Injection Brine
Polymer Pre-flood	5 months 2000 ppm polymer Unsoftened Injection Brine
ASP Slug Composition	5 months 0.3 vol% Surfactant 3% Na_2CO_3 in Softened Injection Brine 4500 ppm polymer
Polymer Drive Composition	5 months 1300 ppm polymer Softened Injection Brine
Water Drive	Unsoftened Injection Brine

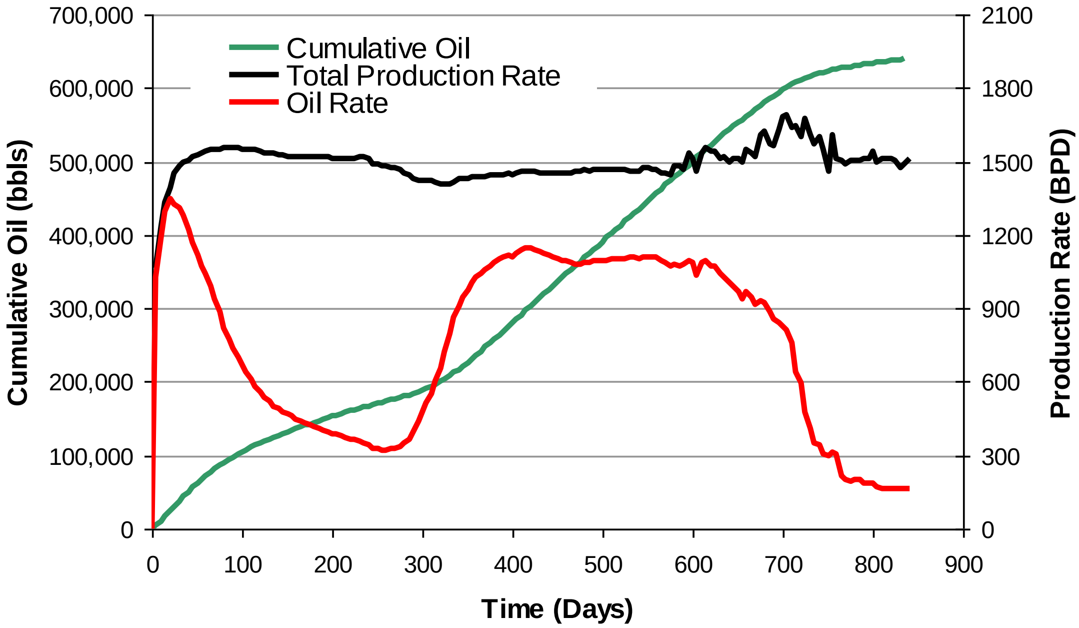

Figure 5-13: Base Case Results - Cumulative Oil Recovered, Total Production Rate and Oil Rate

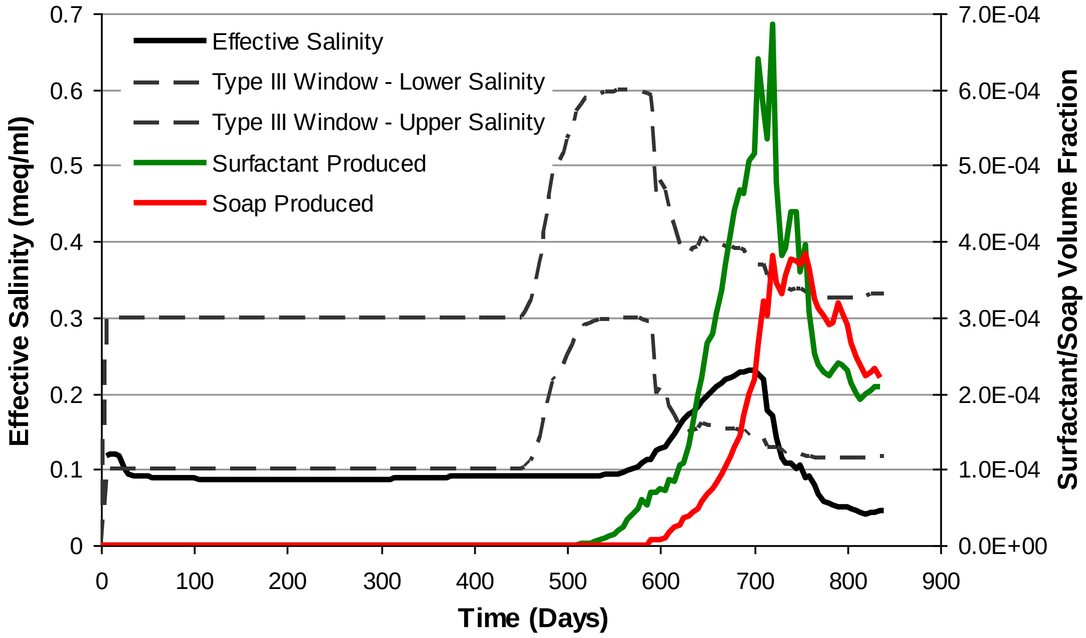

Figure 5-14: Base Case Results - Effective Salinity, Effluent Soap Concentration, and Effluent Surfactant Concentration

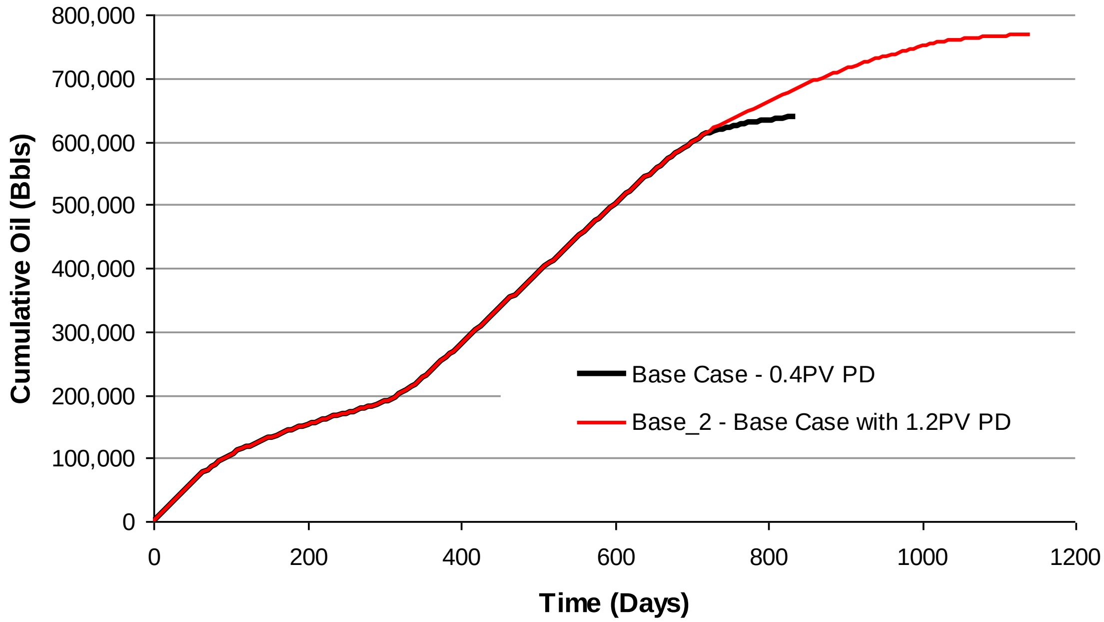

Figure 5-15: Base Case Results- Impact of Increasing Polymer Drive Size on Cumulative Oil

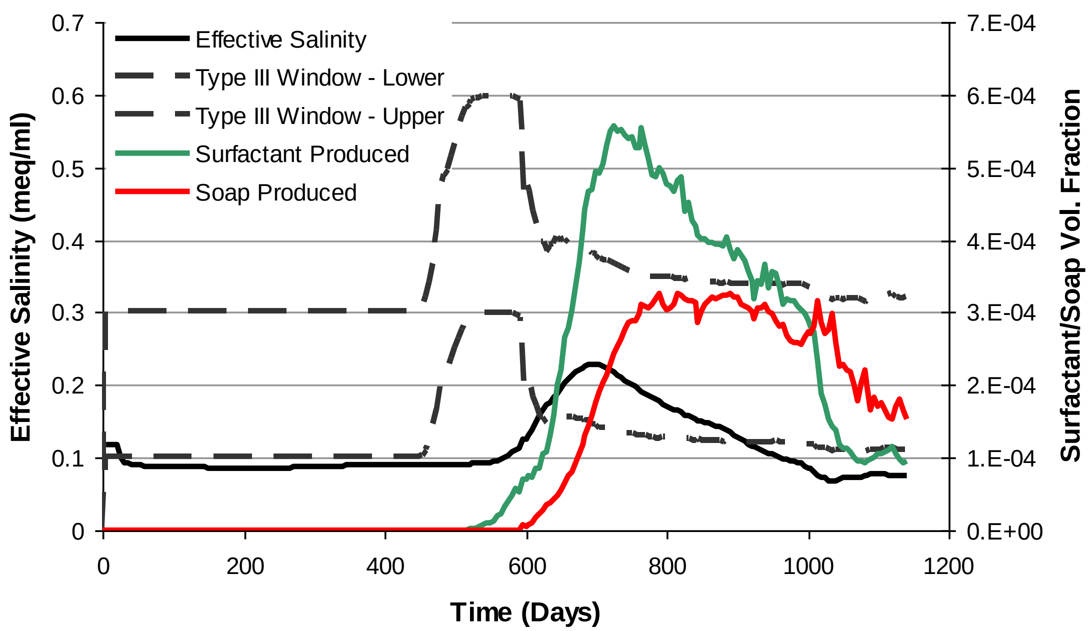

Figure 5-16: Base Case Results - Impact of Increasing Polymer Drive Size on Effluent Salinity, Soap and Surfactant Concentration

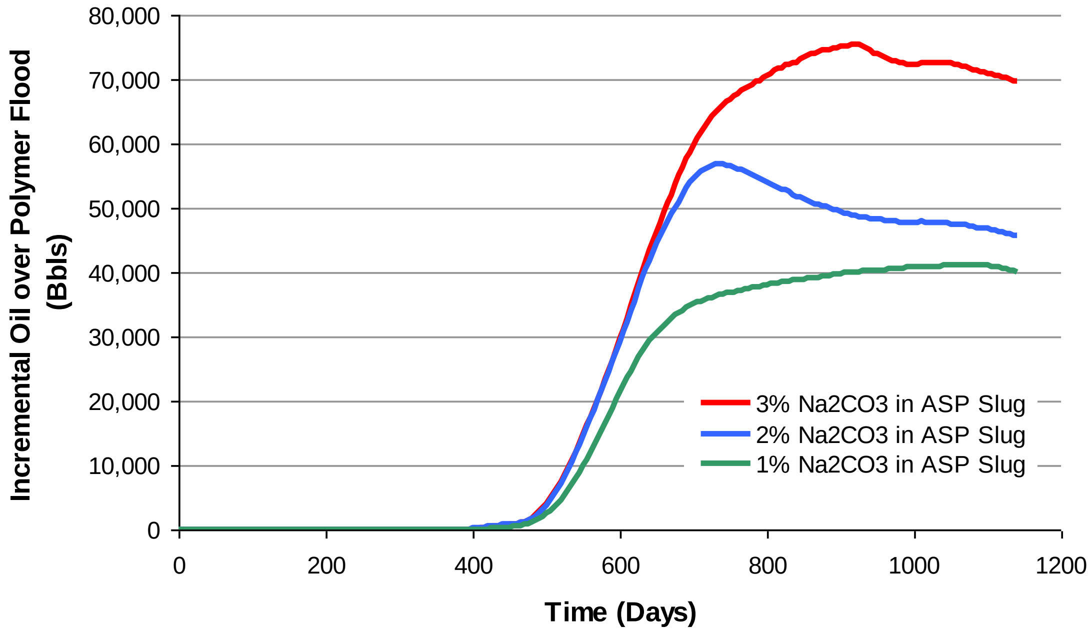

Figure 5-17: Sensitivity to Alkali Concentration in ASP Slug - Incremental Oil Recovered over Polymer Flood

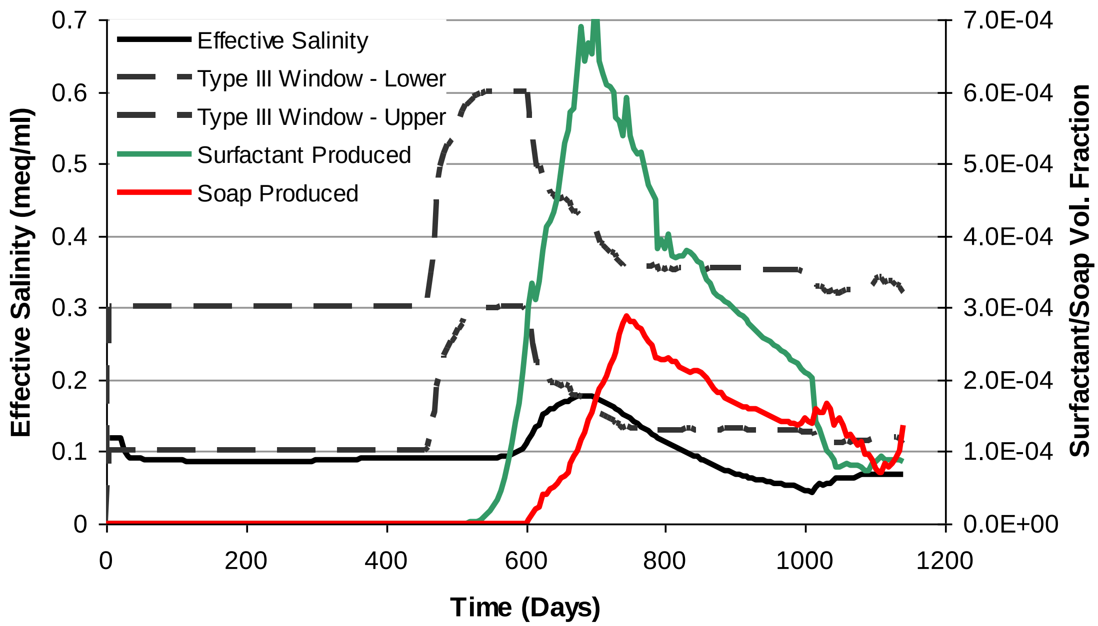

Figure 5-18: Produced Salinity, Soap and Surfactant Concentration - 2% Na_2CO_3 in ASP Slug

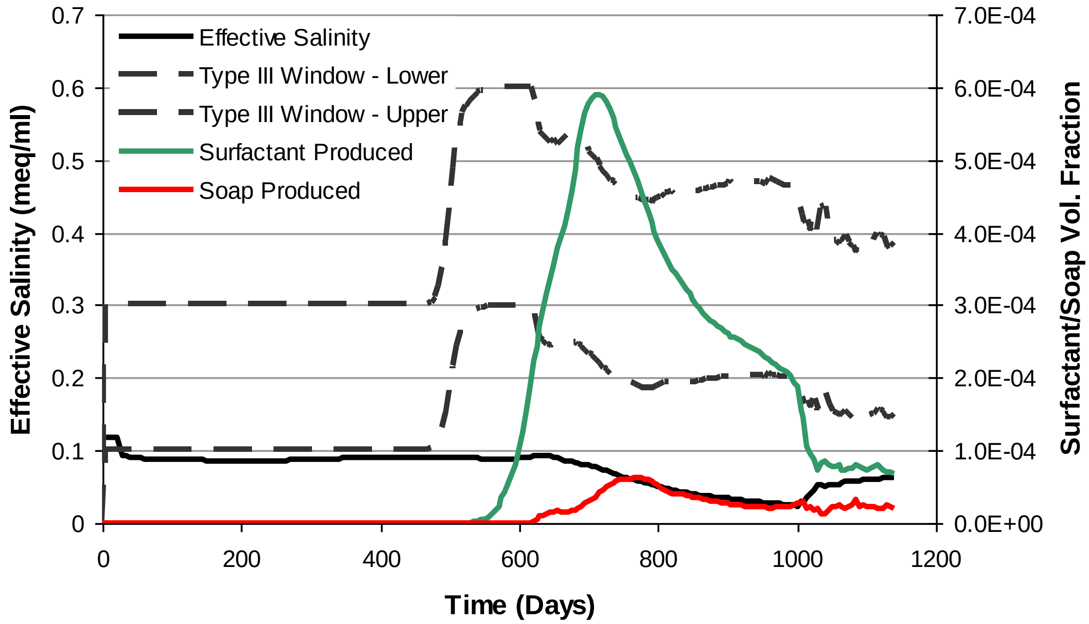

Figure 5-19: Produced Salinity, Soap and Surfactant Concentration - 1% Na_2CO_3 in ASP Slug

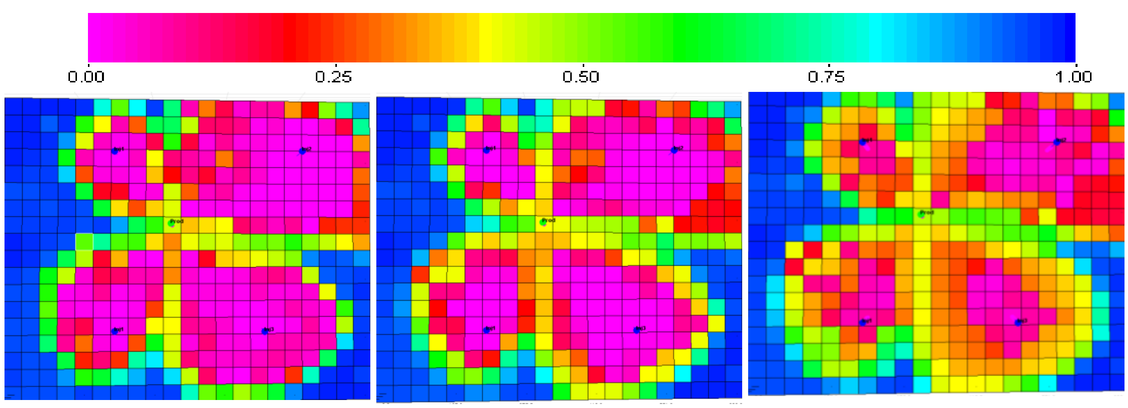

Figure 5-20: 3% Na_2CO_3 **Figure 5-21: 2% Na_2CO_3** **Figure 5-22: 1% Na_2CO_3**

Sensitivity to Alkali Concentration in ASP Slug - Maps of Oil Saturation in Layer 47 after Water Chase

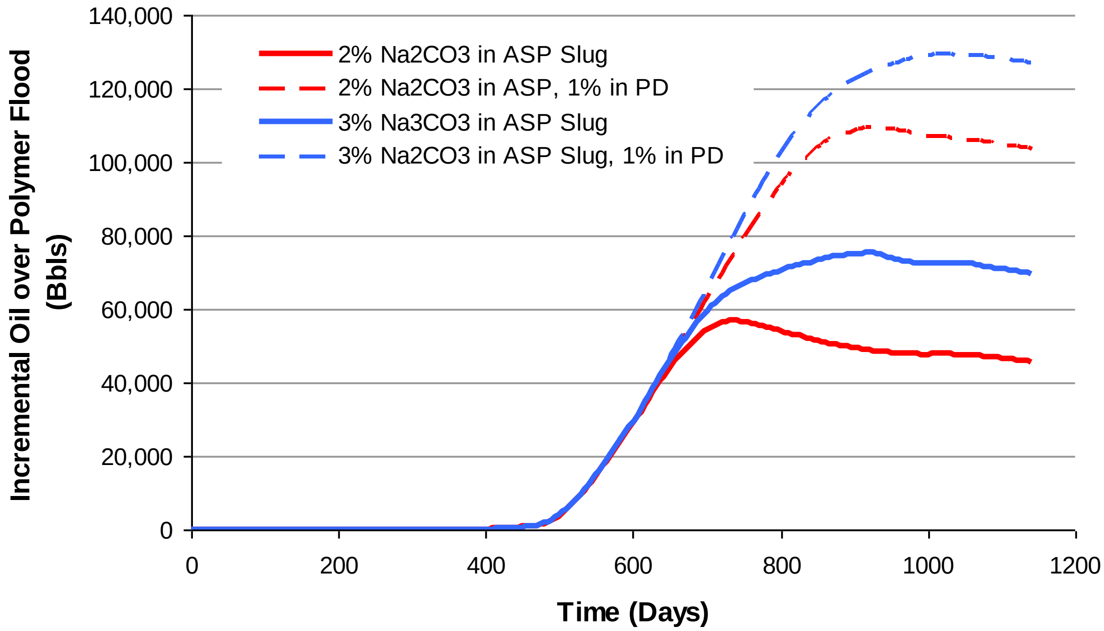

Figure 5-23: Sensitivity to Alkali Concentration in the Polymer Drive - Incremental Oil over Polymer Flood

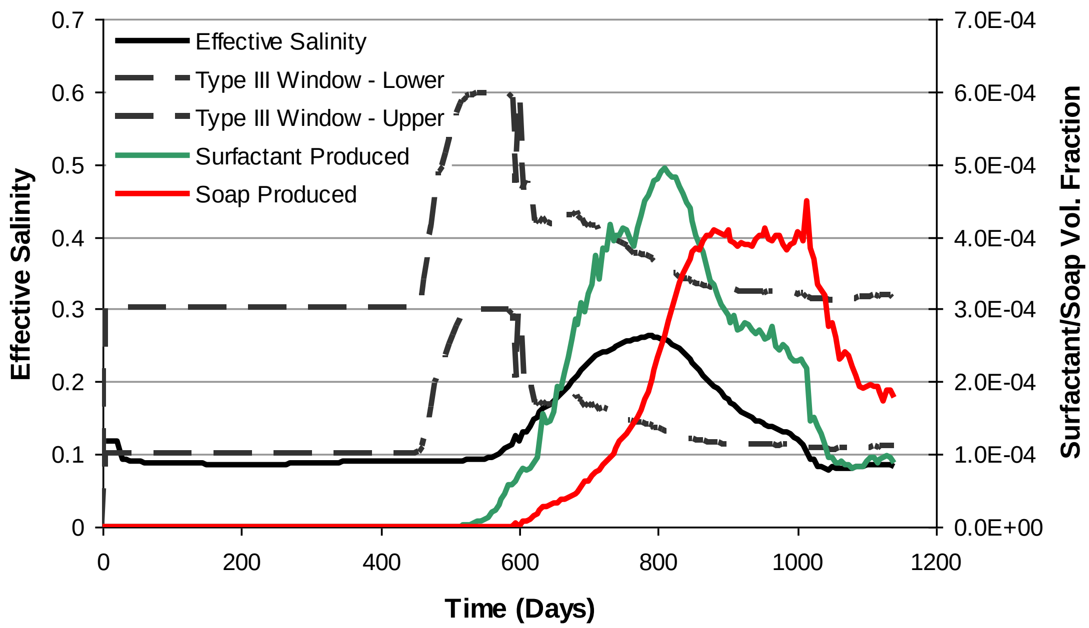

Figure 5-24: Produced Salinity, Soap and Surfactant - 3% Alkali in ASP Slug, 1% Alkali in 5 Months of Polymer Drive

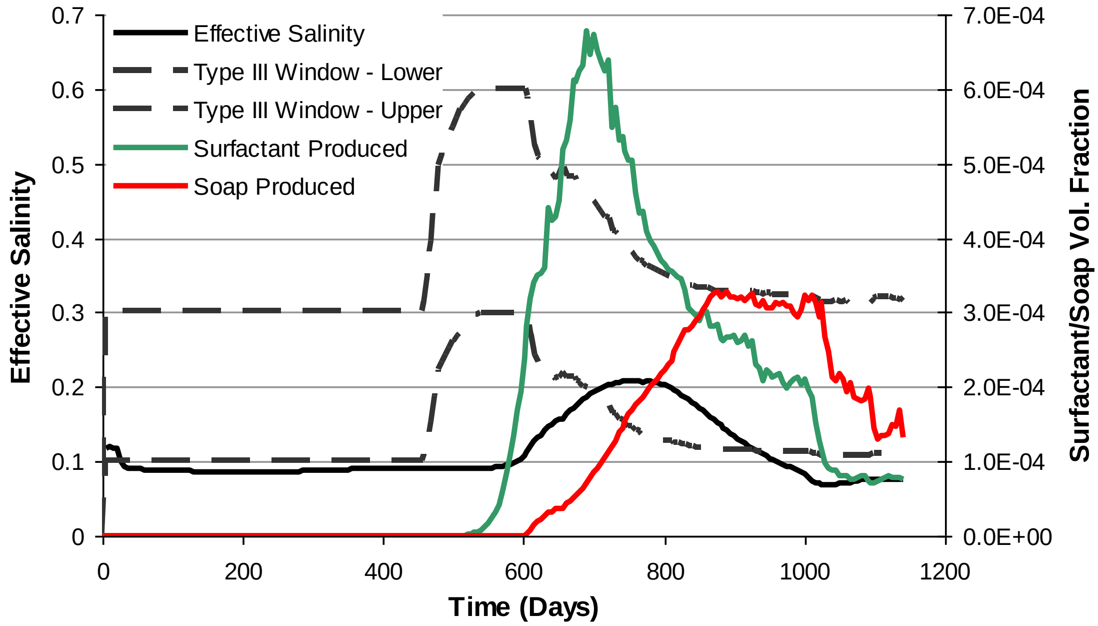

Figure 5-25: Produced Salinity, Soap and Surfactant - 2% Alkali in ASP Slug, 1% Alkali in 5months of Polymer Drive

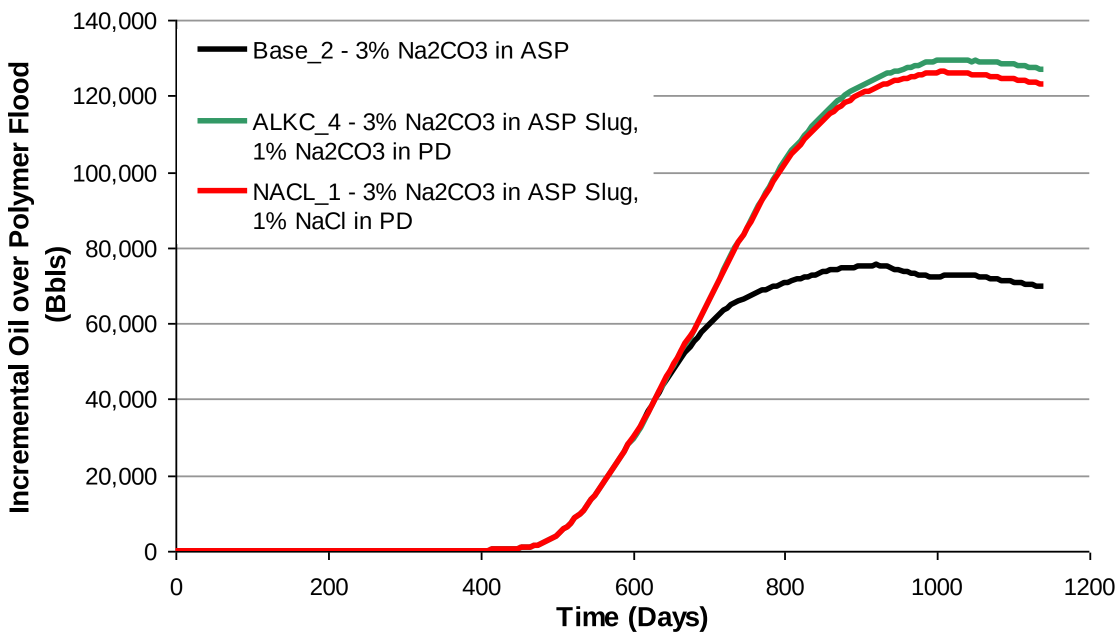

Figure 5-26: Impact of using NaCl instead of Na_2CO_3 in PD - Incremental Oil over Polymer Flood

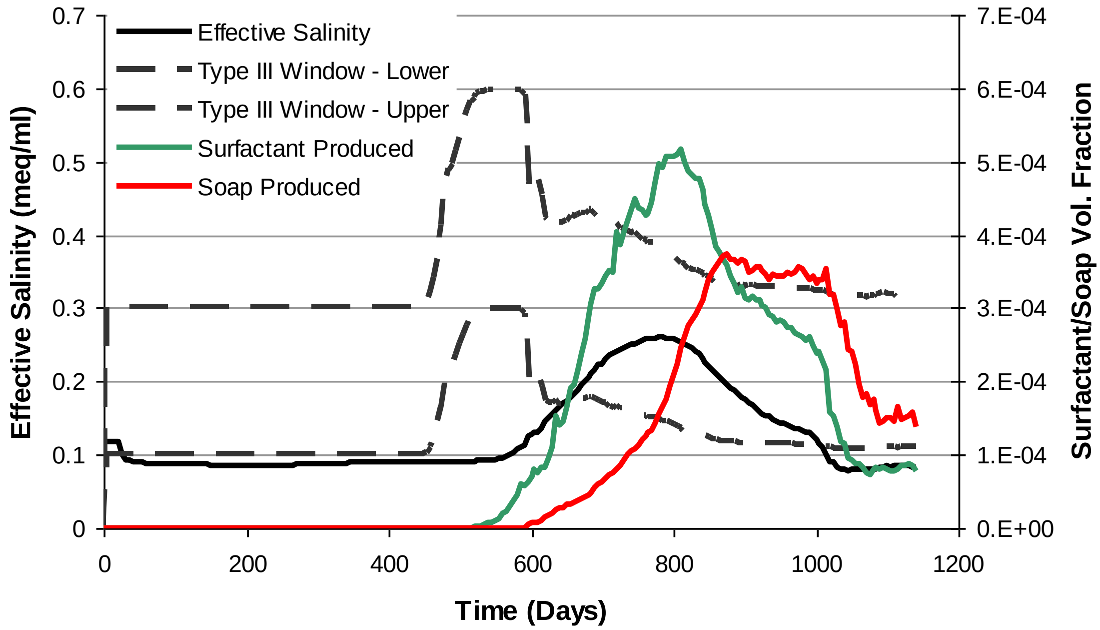

Figure 5-27: Produced Salinity, Soap and Surfactant - Impact of using NaCl instead of Na_2CO_3 in PD

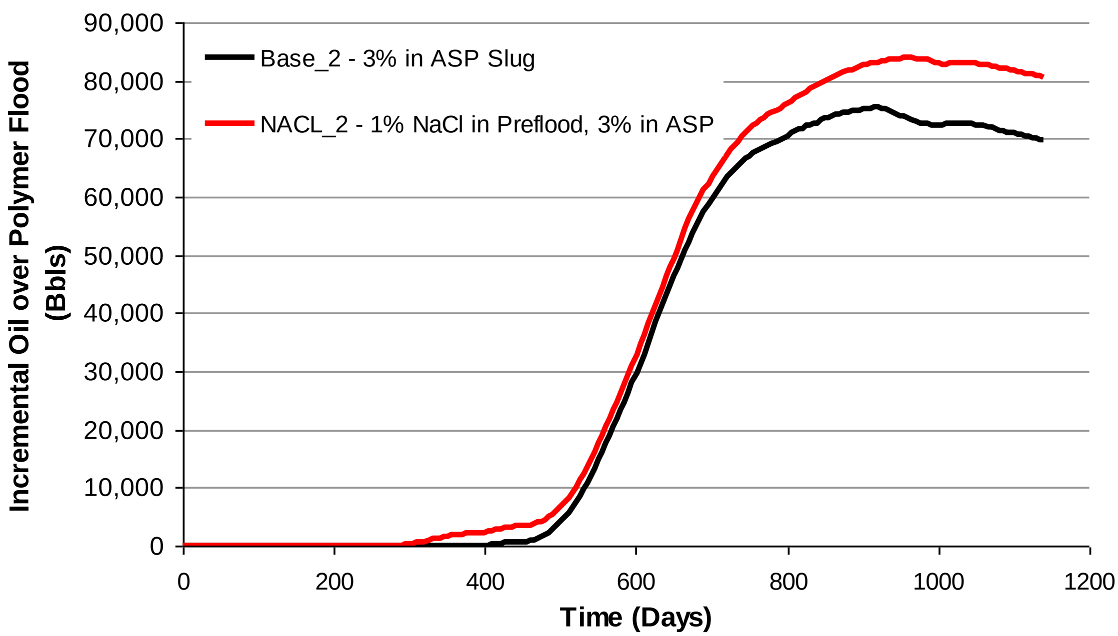

Figure 5-28: Impact of using 1% NaCl in the Pre-flood - Incremental Oil Recovery over Polymer

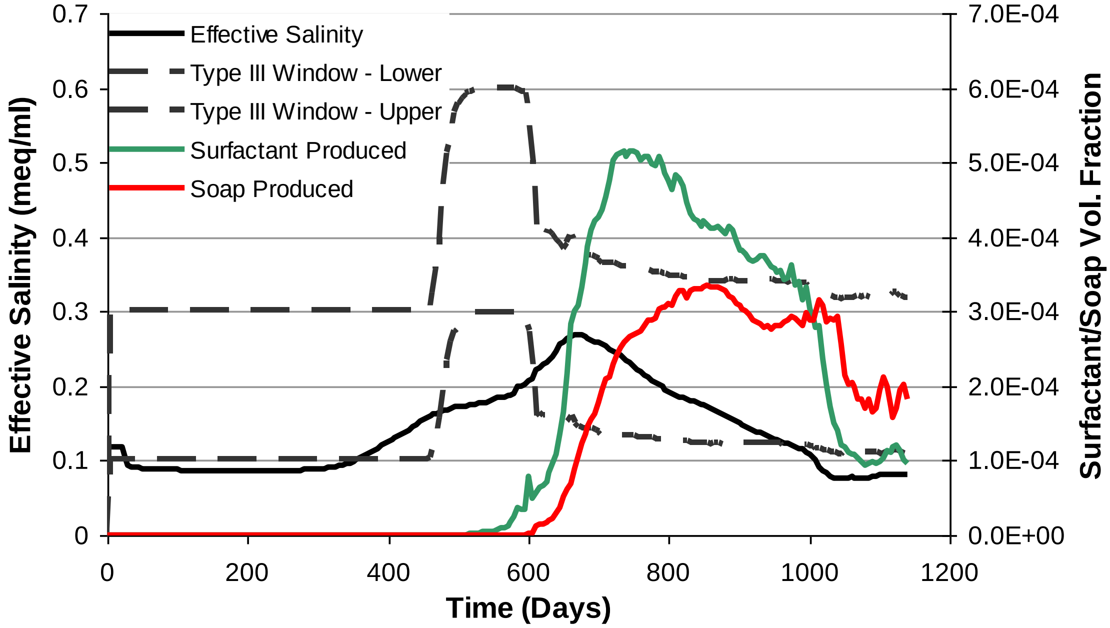

Figure 5-29: Impact of using 1% NaCl in the Pre-flood - Produced Salinity, Soap and Surfactant Concentration

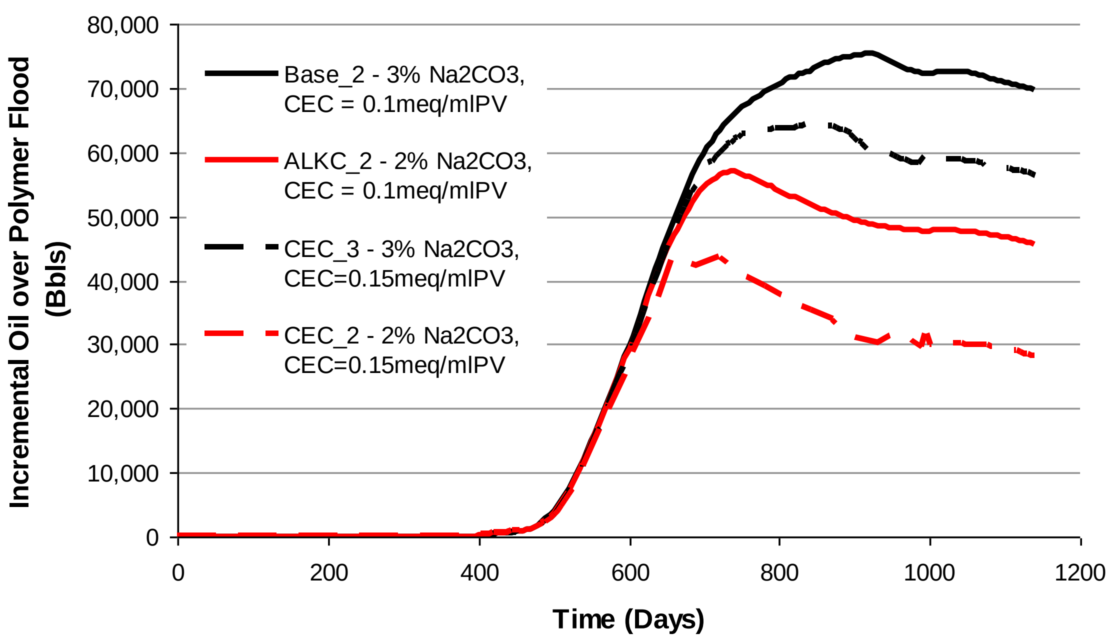

Figure 5-30: Impact of Increasing the CEC - Incremental Oil Comparison

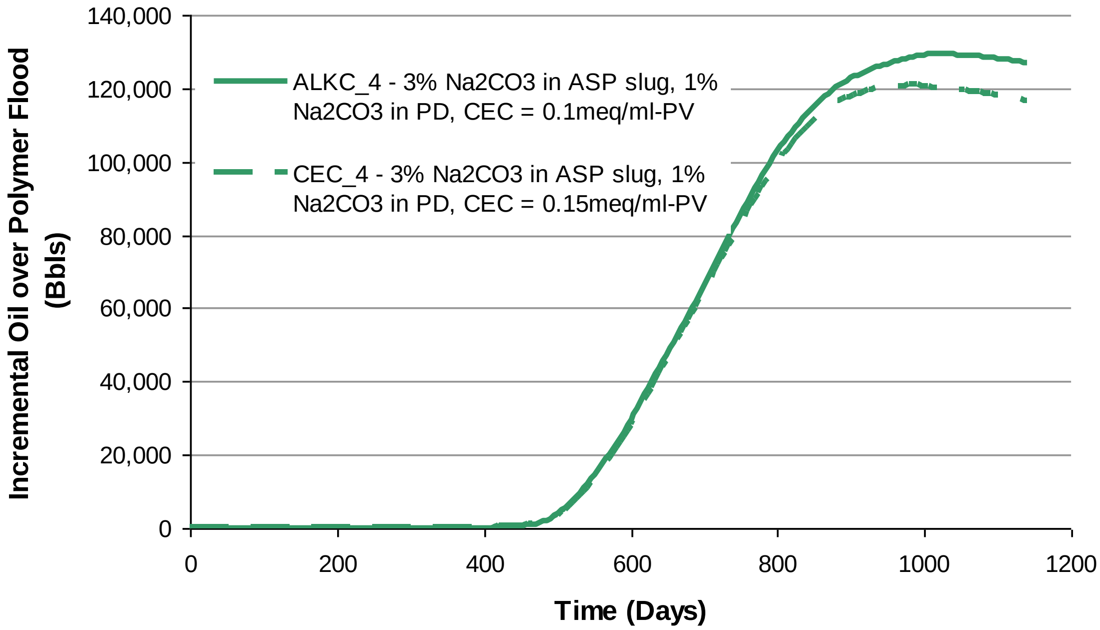

Figure 5-31: Impact of Increasing the CEC and Using Extra Alkali in the Polymer Drive - Incremental Oil Comparison

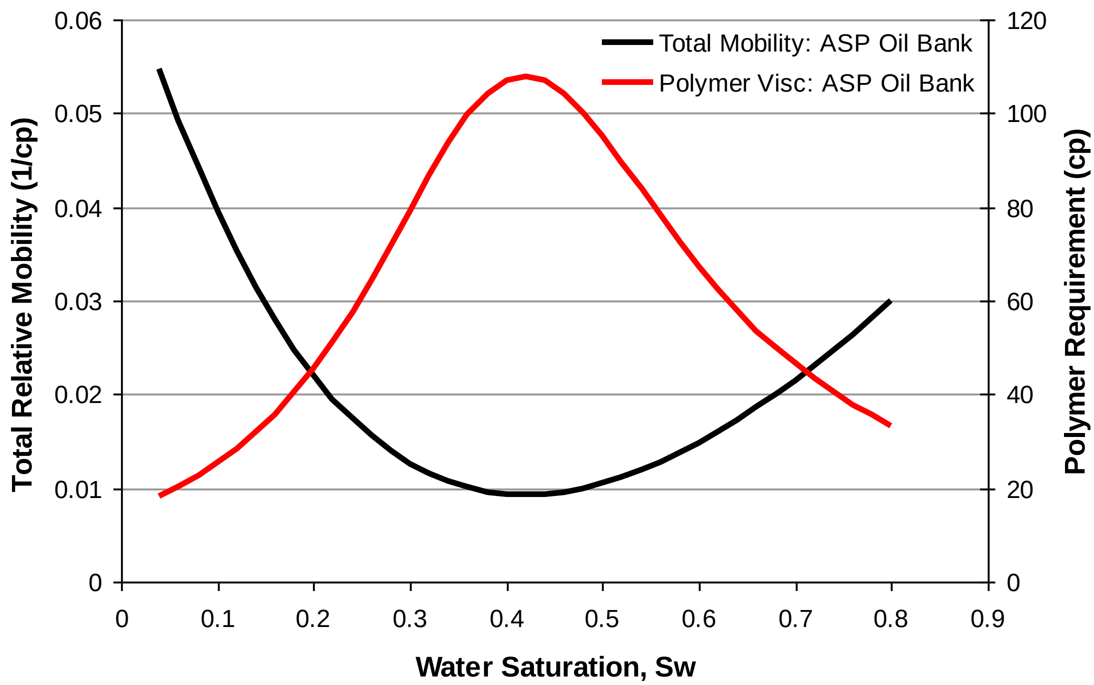

Figure 5-32: Total Relative Mobility - ASP Oil Bank

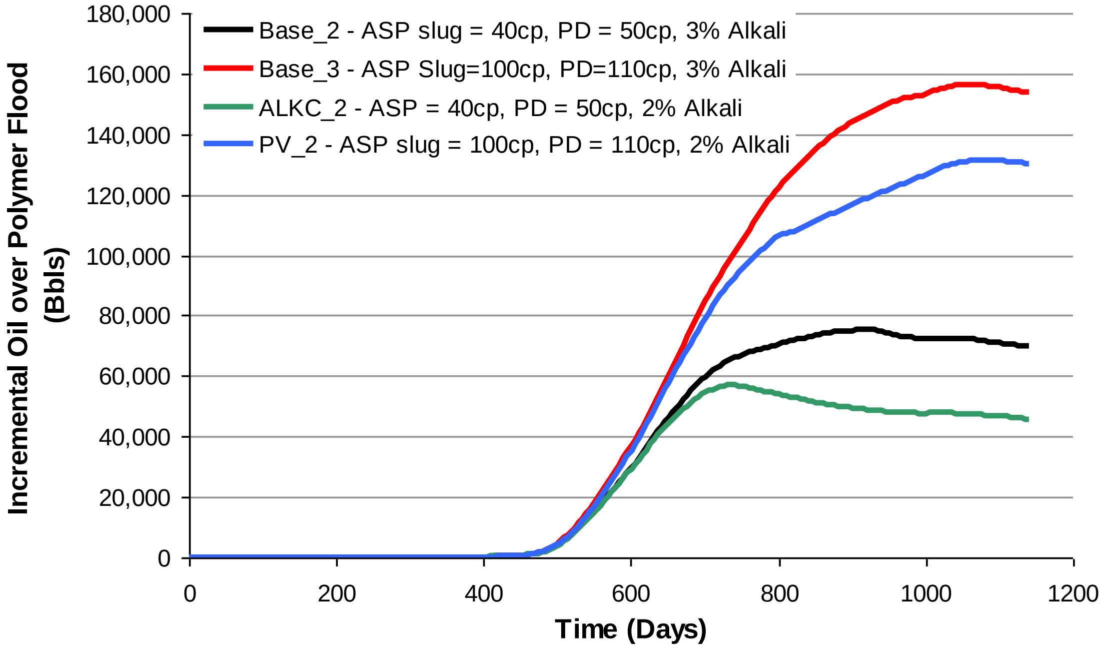

Figure 5-33: Impact of Increasing Slug Viscosities - Incremental Oil Comparison

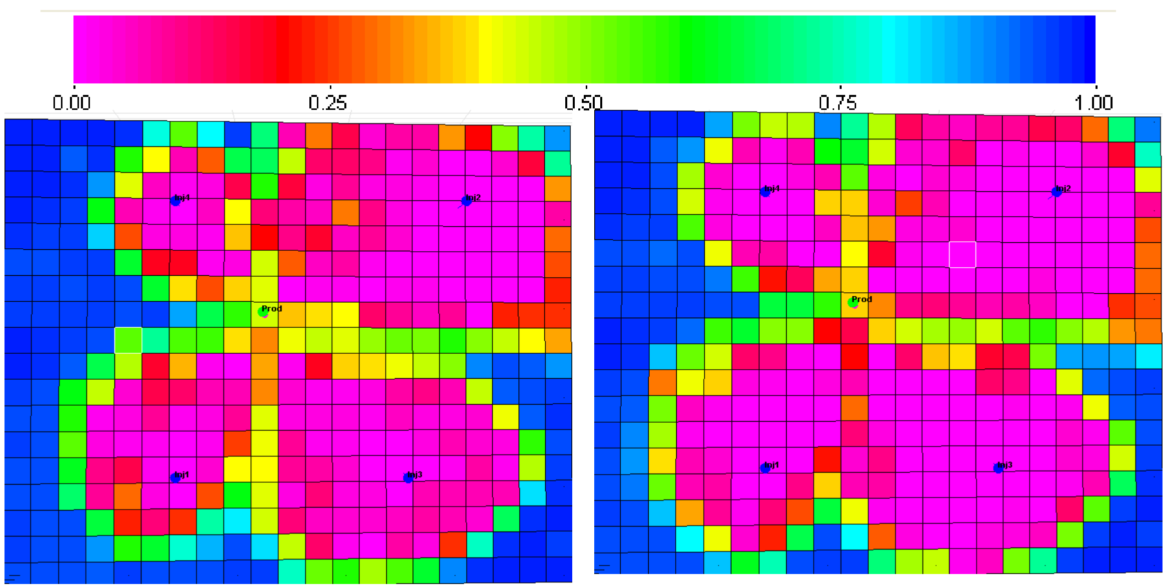

Figure 5-34: Comparison of Final Oil Saturation between Base_2 and Base_3

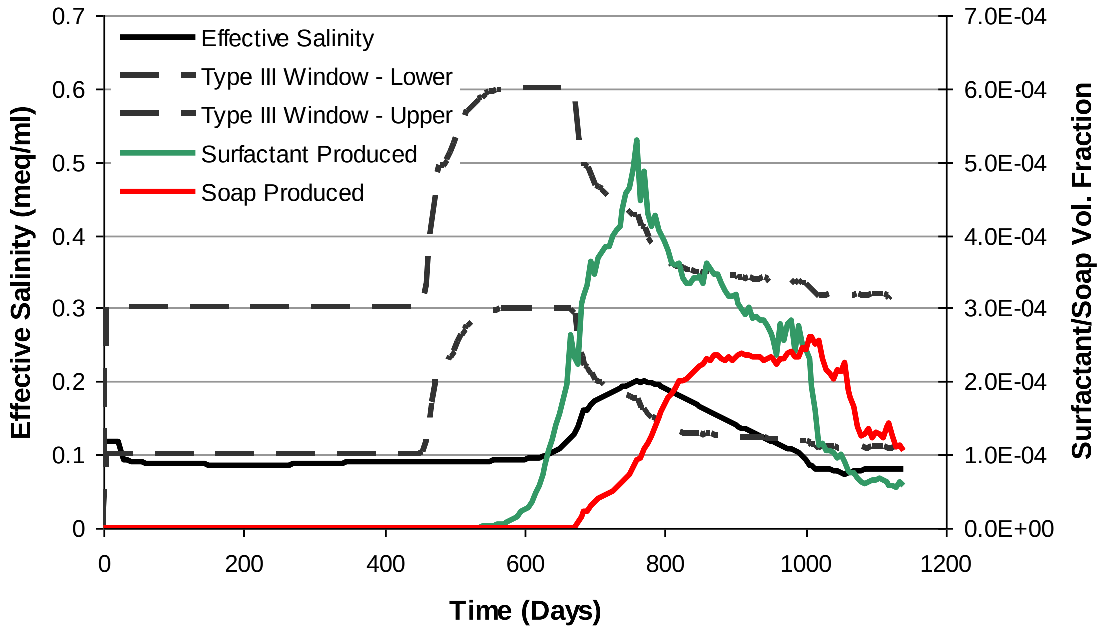

Figure 5-35: Produced Salinity, Soap and Surfactant Concentration - Base_3 results

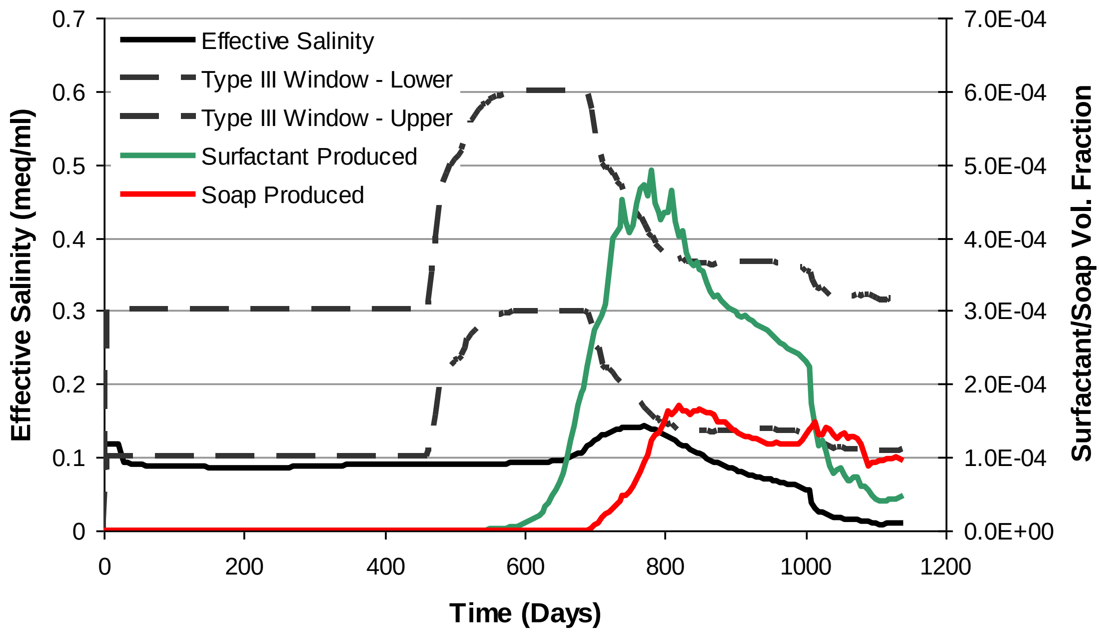

Figure 5-36: Produced Salinity, Soap and Surfactant Concentration - PV_2 results

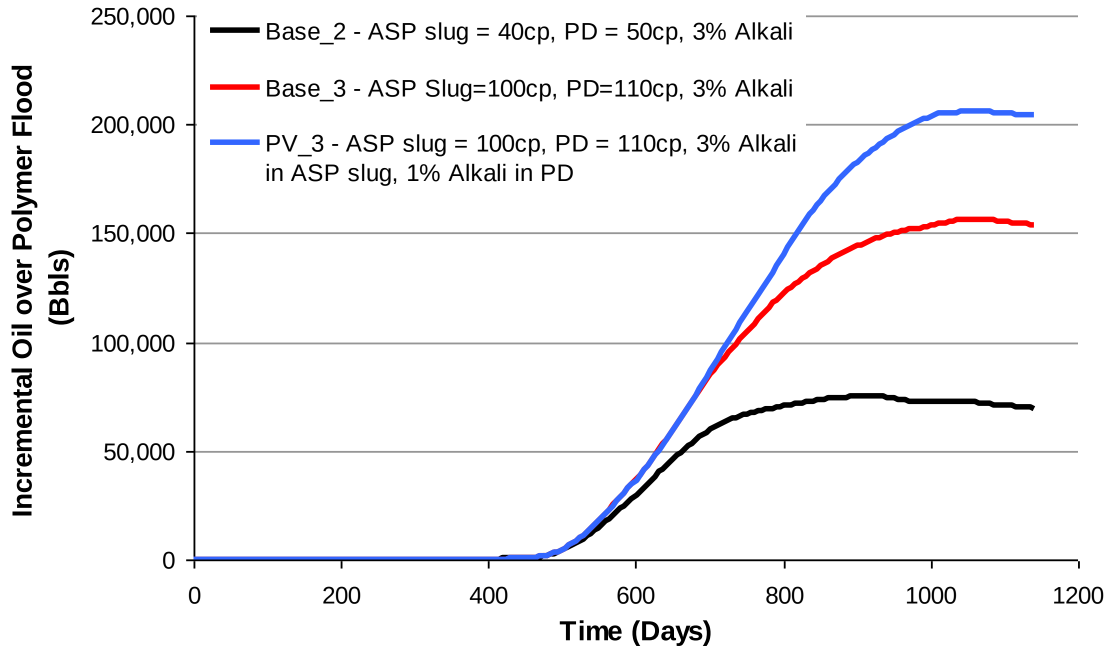

Figure 5-37: Impact of Increasing Slug Viscosities and Alkali Concentration in the Polymer Drive - Incremental Oil Comparison

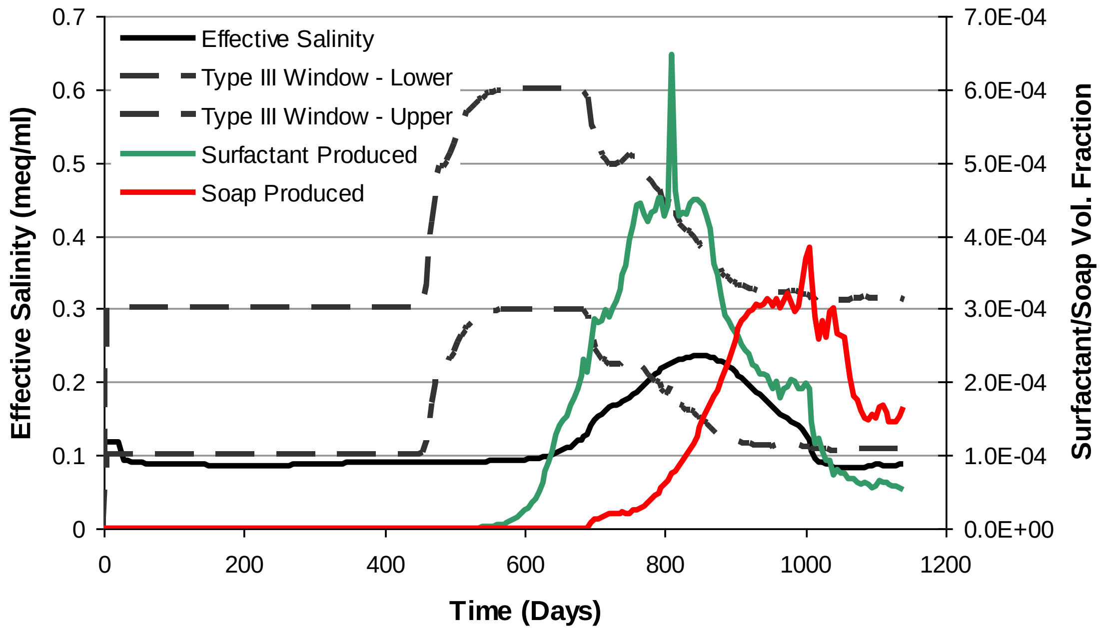

Figure 5-38: Produced Salinity, Surfactant and Soap Concentration - PV_3 Results

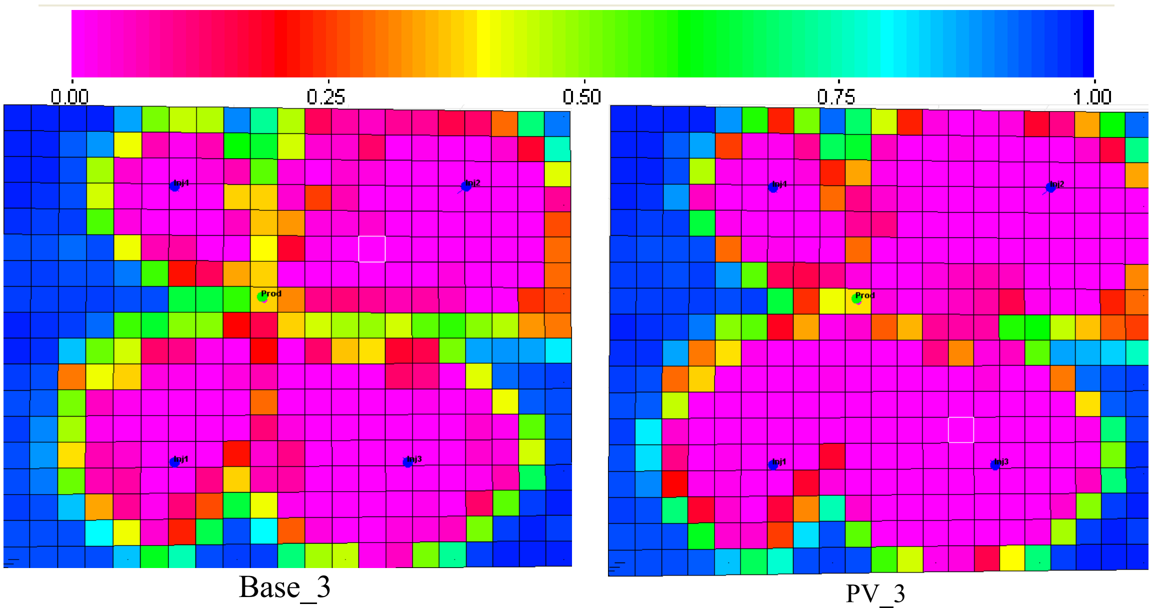

Figure 5-39: Comparison of Final Oil Saturation between Base_3 and PV_3

Table 5-5: Description of Simulations Performed

Simulation Name	Description	Surfactant Slug Size (frac PV)	Surfactant Conc. (vol%)	Alkali Concentration (wt%)		Polymer Drive Size (frac PV)		Polymer Concentration (wt%)			
				in SP	in PD	PD1	PD2	In PF	in SP	in PD1	in PD2
Polymer Flood	Ran pre-flood for 2PV	-	-	-	-	1.6	-	0.200	-	0.200	-
Base_2		0.4	0.3	3	-	0.4	0.8	0.200	0.450	0.130	0.130
ALKC_2	2% Na_2CO_3	0.4	0.3	2	-	0.4	0.8	0.200	0.420	0.130	0.130
ALKC_1	1% Na_2CO_3	0.4	0.3	1	-	0.4	0.8	0.200	0.380	0.130	0.130
ALKC_4	3% Na_2CO_3 in ASP, 1% Na_2CO_3 in PD	0.4	0.3	3	1	0.4	0.8	0.200	0.450	0.410	0.130
ALKC_5	2% Na_2CO_3 in ASP, 1% Na_2CO_3 in PD	0.4	0.3	2	1	0.4	0.8	0.200	0.420	0.410	0.130
NACL_1	3% Na_2CO_3 in ASP, 1% NaCl in PD	0.4	0.3	3	*	0.4	0.8	0.200	0.450	0.401	0.130
NACL_2	1% NaCl in preflood	0.4	0.3	3	-	0.4	0.8	0.260	0.450	0.130	0.130
CEC_3	Base_2 design with CEC=0.15meq/mlPV	0.4	0.3	3	-	0.4	0.8	0.200	0.450	0.130	0.130
CEC_2	ALKC_2 design with CEC=0.15meq/mlPV	0.4	0.3	2	-	0.4	0.8	0.200	0.420	0.130	0.130
CEC_4	ALKC_4 design with CEC=0.15meq/mlPV	0.4	0.3	3	1	0.4	0.8	0.200	0.450	0.410	0.130
Base_3	Increased slug viscosities	0.4	0.3	3	-	0.4	0.8	0.200	0.680	0.230	0.230
PV_2	Increased slug viscosities, 2% Na_2CO_3	0.4	0.3	2	-	0.4	0.8	0.200	0.638	0.230	0.230
PV_3	Increased slug viscosities,3% Na_2CO_3 in ASP, 1% Na_2CO_3 in PD	0.4	0.3	3	1	0.4	0.8	0.200	0.680	0.593	0.230

* 1% NaCl is added for 0.4PV of the Polymer Drive

Table 5-6: Chemical Efficiency for Simulations Performed

Simulation Name	Surfactant Mass (1000lbs)	Inc. Polymer Mass (1000lbs)	Na2CO3 Mass (1000lbs)	Cumulative Oil (bbls)	Incremental Oil (Bbls)	Surfactant Efficiency (lbs/bbl)	Inc. Polymer Efficiency (lbs/bbl)	Inc. Na2CO3 Efficiency (lbs/bbl)	Inc. Chemical Cost per Inc. bbl ($/bbl)
Polymer Flood	-	-	-	701460	-	-	-	-	
Base_2	236.5	31.5	2365.5	773270	71810	3.29	0.44	32.94	15.48
ALKC_2	236.5	7.9	1577.0	747900	46440	5.09	0.17	33.96	20.63
ALKC_1	236.5	-23.6*	788.5	741520	40060	5.90	-0.59	19.68	19.78
ALKC_4	236.5	252.3	3153.9	828960	127500	1.86	1.98	24.74	12.25
ALKC_5	236.5	228.6	2365.5	805300	103840	2.28	2.20	22.78	13.55
NACL_1	236.5	245.2	3153.9	824790	123330	1.92	1.99	25.57	12.57
NACL_2	236.5	79.6	2365.5	781900	80440	2.94	0.99	29.41	14.72
CEC_3	236.5	31.5	2365.5	757020	55560	4.26	0.57	42.57	20.01
CEC_2	236.5	7.9	1577.0	742360	40900	5.78	0.19	38.56	23.42
CEC_4	236.5	252.3	3153.9	817920	116460	2.03	2.17	27.08	13.41
Base_3	236.5	449.5	2365.5	855260	153800	1.54	2.92	15.38	11.30
PV_2	236.5	416.3	1577.0	832870	131410	1.80	3.17	12.00	11.95
PV_3	236.5	735.6	3153.9	905220	203760	1.16	3.61	15.48	11.22

Assumes $3/lb-surfactant, $1.50/lb-polymer, $0.15/lb-$Na_2CO_3$, and $0.15/lb-NaCl
Incremental amounts are calculated over polymer flood.

* Since softened brine is used in the ASP simulations and unsoftened brine is used in the Polymer Flood simulations, the cumulative polymer injected is actually lower in case ALKC_1.

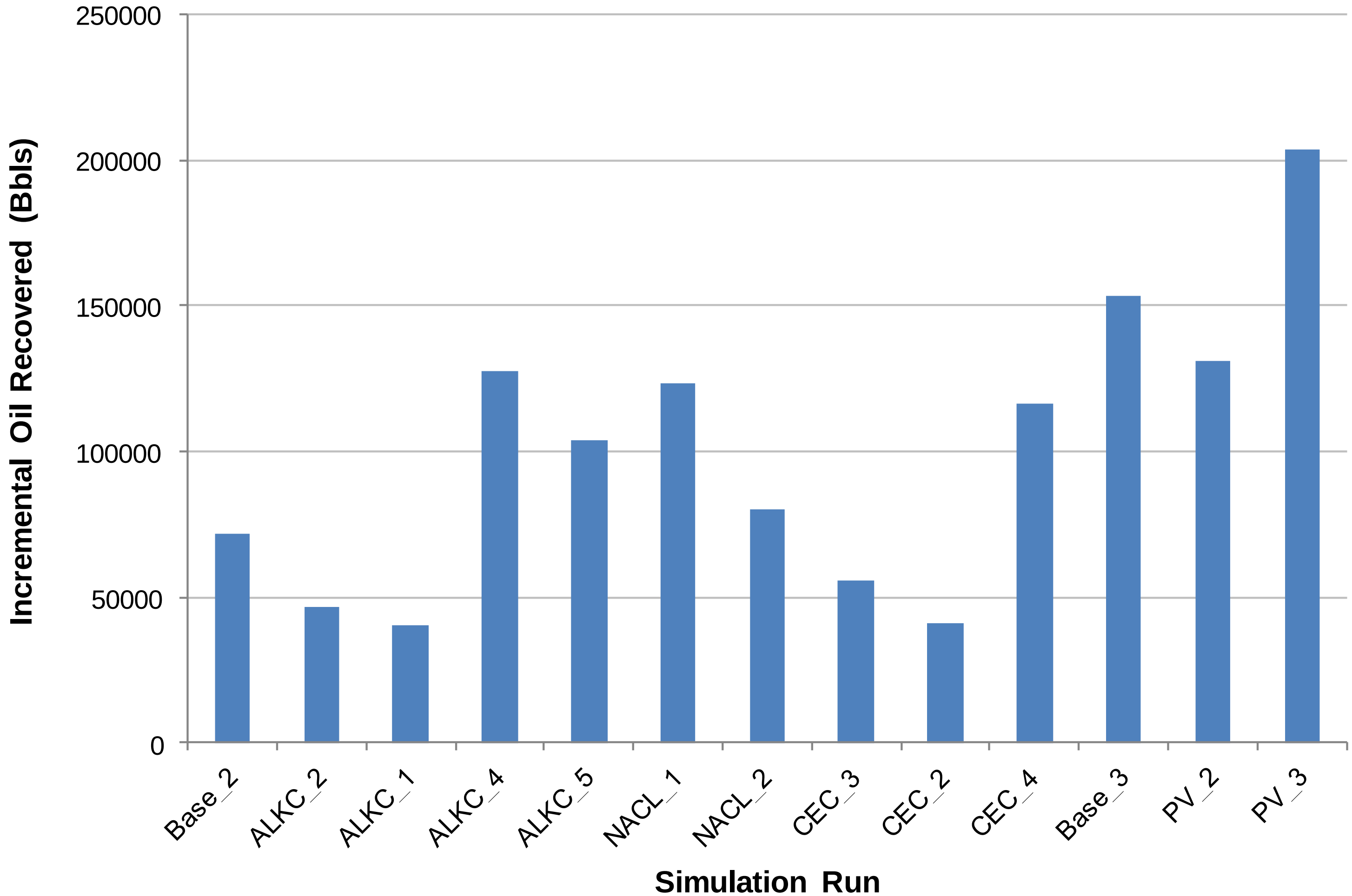

Figure 5-40: Plot of Incremental Oil Recovered For Each Simulation Performed

CHAPTER 6 : SUMMARY AND CONCLUSIONS

Chemical enhanced oil recovery methods have been studied for some time now and several successful field-scale applications of these processes have been reported in the literature, some of which are highlighted in Chapter 2. Since these processes are significantly more complex than waterflooding, it is important to perform a detailed design study in order to ensure the success of pilot- and field-scale chemical floods. The goal of the research was to use reservoir simulation to identify uncertain parameters that can significantly affect the oil recovery, and to then propose a robust design to reduce the uncertainty.

In Chapter 3, it was shown that inverted 5-spot patterns are significantly more efficient than normal 5-spot patterns in recovering residual oil because of better chemical confinement. The impact of uncertainties in the oil-bank mobility on recovery was also demonstrated. It was observed that since the oil inside the pilot area is not completely confined in an inverted 5-spot pattern, that this configuration is also more sensitive to oil-bank mobility. A sensitivity to the oil exponent of the Corey relative permeability was done for both types of patterns. A higher oil exponent reduces the oil bank mobility. This reduction had more impact on the inverted 5-spot than on the regular 5-spot. A higher oil exponent required a higher polymer concentration to be stable, but the inverted 5-spot is still more sensitive even when stable. Injecting higher than the minimum polymer concentration needed for a unit mobility ratio reduced the sensitivity to the relative permeability parameters at high capillary numbers. Finally, it was demonstrated that even though the inverted 5-spot pattern was more sensitive to oil-bank mobility, the higher chemical efficiency compensates for this effect and recovers more oil than a normal 5-spot pattern..

The impact of grid refinement on oil recovery and project life for a low-permeability, high-temperature carbonate reservoir was demonstrated in Chapter 4. It was observed that the sweep efficiency improved when the simulation grid was refined and this led to more oil being mobilized by the surfactant. This is because the surfactant is artificially diluted to concentrations below its CMC when a coarse grid is used. When a fine grid was used, the surfactant concentration is greater than the CMC so the capillary number is high, which in turn results in a higher values of oil and water relative permeability and therefore also a higher injectivity. It was also demonstrated that uncertainties in the permeability reduction factor and the effective in-situ shear rate have a significant impact on the project life without a significant impact on the oil recovery. Even a polymer concentration on the order of 2000 ppm, which is less than needed for a unit mobility ratio, resulted in a significant improvement in the chemical efficiency.

The design of an alkali-surfactant-polymer flood was presented in Chapter 5. The goal of this research was to optimize the salinity gradient and alkali concentration. Adding NaCl or Na_2CO_3 to the first part of the polymer drive makes the salinity gradient more favorable and the oil recovery increases significantly. Even when the CEC was high, an ASP slug with 3 wt% alkali concentration resulted in higher oil recovery than 2 wt%. Also, adding sodium carbonate to the first part of the polymer drive makes the design less sensitive to the cation exchange capacity. Finally, the importance of good mobility control on the efficiency of the flood was also demonstrated here. Because the reservoir was pre-flooded with a polymer solution, the oil-bank due to the ASP slug has a lower mobility than a design without a polymer pre-flood. Increasing the polymer concentration in the ASP slug and Polymer Drive to reduce the mobility ratio to one significantly increased the oil recovery and the chemical efficiency.

Appendix A: Input File for Base Case simulation in Chapter 3

```
*****************************************************************************
CC                                          *
CC    BRIEF DESCRIPTION OF DATA SET : UTCHEM (VERSION 2011-9)              *
CC                                          *
CC***************************************************************************
CC                                            *
CC   SP Flood Pilot Evaluation              *
CC                                            *
CC  LENGTH (FT) : 2625'           PROCESS : SP                   *
CC  THICKNESS (FT) : 16'           PRESSURE (i) CONSTRAINTS          *
CC  WIDTH (FT) : 1715'            COORDINATES : CARTESIAN                *
CC  POROSITY : varies, 0.20 avg     DAY SPECIFICATION              *
CC  GRID BLOCKS : 79x49x9=33,075    COURANT NUMBER SPECIFICATION       *
CC  UNIFORM GRIDBLOCK SIZES        WELL SKIN = 0                     *
CC                                                   *
CC***************************************************************************
CC                                            *
CC***************************************************************************
CC                                          *
CC    RESERVOIR DESCRIPTION                              *
CC                                          *
CC***************************************************************************
CC
CC Run number
*---- RUNNO
Case9a
CC
CC Title and run description
*---- title(i)
Case9a:
CC
CC
CC
CC SIMULATION FLAGS: IMODE = 1 for new case, IMODE=2 for restart
*---- IMODE IMES IDISPC ICWM ICAP IREACT IBIO ICOORD ITREAC ITC  IGAS  IENG  idual
itens
      1   2    3    0   0    0    0    1     0    0   0    0     0      0
CC
CC no. of gridblocks,flag specifies constant or variable grid size,unit
*---- NX    NY    NZ  IDXYZ  IUNIT
     75    49     9     2      0
CC
CC VARIABLE GRID SIZE ON A REGIONAL BASIS IN X DIRECTION
*---- II1, II2, DX1
  75*35
CC
CC VARIABLE GRID SIZE ON A REGIONAL BASIS IN Y DIRECTION
*---- JJ1, JJ2, DY1
 49*35
```

```
CC
CC VARIABLE GRID SIZE ON A REGIONAL BASIS IN Z DIRECTION
*---- KK1, KK2, DZ1
4*1.84
5*1.75
CC
CC total no. of components,no. of tracers,no. of gel components
*----n    no    ntw    nta    ngc    ng    noth
    10    0     2     0     0     0      0
CC
CC Name of the components
*----spname(i) for i=1 to n
Water
Oil
Surf.
Polymer
Chloride
Calcium
Alcohol1
Alcohol2
Trace1
Trace2
CC
CC flag indicating if the component is included in calculations or not
*----icf(kc) for kc=1,n
     1  1  1  1  1  1  0 0 1 1 0 0 0 0 0 0 0 0 0 0
CC
CC*******************************************************************
CC                                           *
CC  3.2  OUTPUT OPTIONS                                *
CC                                           *
CC*******************************************************************
CC
CC
CC 3.2.1 FLAG TO WRITE TO UNIT 3,FLAG FOR PV OR DAYS TO PRINT OR TO STOP THE RUN
*---- ICUMTM  ISTOP  IOUTGMS             IS3G
      0      0      0              0
CC
CC 3.2.2 FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*---- IPRFLG(KC),KC=1,N
     1  1  1  1  1  1  0 0 1 1 0 0 0 0 0 0 0 0 0 0
CC
CC 3.2.3 FLAG FOR PRES.,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE
PROFILES
*---- IPPRES IPSAT IPCTOT IPBIO IPCAP IPGEL IPALK IPTEMP IPOBS
      1     1     1     0    0    0    0    0    0
CC
CC 3.2.4 FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 4 (Prof)
*---- ICKL IVIS IPER ICNM ICSE IHYSTP IFOAMP INONEQ
     1   1   1   1   1   0   0   0
CC
CC 3.2.5 FLAG  for variables to PROF output file
```

```
*---- IADS IVEL IRKF IPHSE
     1   1   1   1
CC
CC*****************************************************************
CC                                             *
CC  3.3     RESERVOIR PROPERTIES                        *
CC                                             *
CC*****************************************************************
CC
CC
CC 3.3.1 MAX. SIMULATION TIME (days)
*---- TMAX
    720
CC
CC 3.3.2 ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*---- COMPR              PSTAND
      0.000003          1270.
CC  value=0 for constant, =1 by layer, =2 for each gridblock, =3 ratio, =4 for include file
CC 3.3.3 use EDITS to PERM,POR,NTG files to make all cells active, but low perm&poros in formerly
inactive cells.
*---- IPOR1  IPERMX IPERMY IPERMZ IMOD  ITRANZ  INTG INTG=1:read in NTG file
      4     4     3     3    1      0     1
CC
CC 3.3.13 Y DIRECTION PERMEABILITY IS DEPENDENT ON X DIRECTION PERMEABILITY
*---- FACTY,   CONSTANT PERMEABILITY MULTIPLIER FOR Y DIRECTION PERMEABILITY
      1
CC
CC 3.3.17 Z DIRECTION PERMEABILITY IS DEPENDENT ON X DIRECTION PERMEABILITY
*---- FACTZ, CONSTANT PERMEABILITY MULTIPLIER FOR Z DIRECTION PERMEABILITY
      1.0
CC  =0 for constant, =1 by layer, =2 by gridblock, =4 separate file, =-1 for backward compatbility
CC 3.3.18 FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER
SATURATION,INITIAL AQUEOUS PHASE cOMPOSITIONS
*----IDEPTH  IPRESS  ISWI  ICWI
     4      4     4    2
CC
CC 3.3.52 BRINE SALINITY AND DIVALENT CATION CONCENTRATION (MEQ/ML)
*---- C50      C60
    0.336    0.062
CC
CC FLAG FOR RESERVOIR PROPERTY MODIFICATION
*----IMPOR  IMKX  IMKY  IMKZ  IMSW
     1    0    0    1    0
CC
CC NUMBER OF REGIONS WITH MODIFIED X PERMEABILITY
*---- NMOD1
     1
CC
CC use EDITS to PERM,POR,NTG file to make all cells active, but low perm in formerly inactive cells.
*---- IMIN    IMAX    JMIN    JMAX    KMIN     KMAX    IFACT    FACTX
     1      75    1       49       1      9      2        1.01
CC
```

```
CC NUMBER OF REGIONS WITH MODIFIED Z PERMEABILITY
*---- NMOD3
     3
CC
CC FIRST AND LAST INDEX IN X,Y,Z DIRECTION,MODIFIED METHOD,CONSTANT VALUE.
*---- IMIN   IMAX   JMIN   JMAX    KMIN    KMAX   IFACT   FACTX
     1     75     1     49       1      3      2       0.3
     1     75     1     49       4      4      2       0.01
     1     75     1     49       5      9      2       0.4
CC
CC*****************************************************************
CC                                                *
CC   3.4 PHYSICAL PROPERTY DATA                                 *
CC                                                *
CC*****************************************************************
CC
CC 3.4.1 OIL CONC. AT PLAIT POINT FOR TYPE II(+)AND TYPE II(-), CMC
CC                CMC
*---- c2plc  c2prc   epsme   ihand
      0     1    0.0001    0
CC
CC 3.4.2 flag indicating type of phase behavior parameters
*---- ifghbn=0 for input height of binodal curve; =1 for input sol. ratio
      0
CC 3.4.3 SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*---- hbns70   hbnc70   hbns71   hbnc71   hbns72   hbnc72
      0   0.03      0    0.015    0    0.03
CC 3.4.5 SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*---- hbns80  hbnc80  hbns81  hbnc81  hbns82  hbnc82
      0      0      0      0      0      0
CC
CC 3.4.6 LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*---- csel7   cseu7   csel8   cseu8
    0.370      0.541   0.    0.
CC 3.4.7 THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
CC   Ca    Alcohol#1  Alcohol#2
*---- beta6    beta7    beta8
      0.0       0      0
CC
CC 3.4.8 FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*---- ialc   opsk7o   opsk7s   opsk8o   opsk8s
      0     0       0       0       0
CC  these are used only for alcohol partitioning in a two alcohol system:
CC 3.4.9 NO. OF ITERATIONS, AND TOLERANCE
*---- nalmax     epsalc
      20      0.0001
CC 3.4.10 ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
CC   aq-oleic   aq-oleic  surf-oleic
*---- akwc7     akws7     akm7       ak7      pt7
     4.671    1.79       48       35.31    0.222
```

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CC
CC 3.4.11 ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*---- akwc8     akws8    akm8    ak8     pt8
       0         0        0      0       0
CC
CC 3.4.22 ift model flag
*----  ift=0 for Healy&Reed; =1 for Chun Huh correl.
       1
CC 3.4.24 INTERFACIAL TENSION PARAMETERS
CC    typ=.1-.35   typ=5-20
*---- chuh         ahuh
     0.3           10
CC 3.4.25 LOG10 OF OIL/WATER INTERFACIAL TENSION
CC     units of log 10 dynes/cm = mN/m
*---- xiftw
      1.5
CC 3.4.26 ORGANIC MASS TRANSFER FLAG
CC    imass=0 for no oil sol. in water.  icorr=0 for constant MTC
*---- imass   icor
       0       0
cc
cc
*--- IWALT    IWALF
      0       0
CC 3.4.31 CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
CC              AQ     OLEIC     ME
*---- itrap      t11      t22      t33
       2       1865    10000    364.2
CC    iperm=0 for constant; =1 varies by layer; =2 varies by gridblock
CC  3.4.32 FLAG FOR RELATIVE PERMEABILITY AND CAPILLARY PRESSURE MODEL
*---- iperm         irtype
       0             0
CC
CC 3.4.35 FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*---- isrw    iprw    iew
       0      0       0
CC
CC 3.4.37 CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*---- s1rwc      s2rwc     s3rwc
      0.28      0.282      0.28
CC
CC 3.4.44 CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*---- p1rwc     p2rwc    p3rwc
      0.268    0.788      0.268
CC
CC 3.4.51   CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY
NO.
*---- e1wc     e2wc       e3wc
     2.0        2.0      2.0
CC
CC 3.4.58 RES. SATURATION OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*---- s1rc   s2rc   s3rc
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      0      0.08       0
CC
CC 3.4.59 ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*---- p1rc   p2rc   p3rc
      1     1     1
CC
CC 3.4.60 REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*---- e13c   e23c   e31c
      1     1     1
CC 3.4.61 WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
CC   water     oil       =0 for isothermal modeling
*---- VIS1     VIS2   TSTAND
     0.933       10.9       0
CC
CC 3.4.80 COMPOSITIONAL PHASE VISCOSITY PARAMETERS for microemulsion
*----   ALPHAV1   ALPHAV2   ALPHAV3   ALPHAV4  ALPHAV5
        2.1        2.1         0.1         0.1       0.1
CC
CC 3.4.81 PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*---- AP1      AP2      AP3
      35       30      1000
CC
CC 3.4.82 PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG
CSEP
*---- BETAP    CSE1     SSLOPE
      1      0.01        -0.5264
CC
CC 3.4.83 PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*---- GAMMAC   GAMHF   POWN   ipmod    ISHEAR   RWEFF  GAMHF2
      4        15      1.7      0       1       1.0    0.0
CC
CC 3.4.84  FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*---- IPOLYM    EPHI3    EPHI4    BRK     CRK   rkcut
      1         1         1      100    0.015      10
CC 3.4.85 SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,8 ,Coeffient of oil and GRAVITY FLAG
CC   if IDEN=1 ignore gravity effect; =2 then include gravity effect
*---- DEN1     DEN2      DEN23     DEN3      DEN7    DEN8    IDEN
     0.43     0.377     0.377      0.433     0.346    0        2
CC   ISTB=0:BOTTOMHOLE CONDITION , 1: STOCK TANK
CC 3.4.93 FLAG FOR CHOICE OF UNITS when printing
*----- ISTB
       0
CC
CC 3.4.95 COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----   COMPC(1)          COMPC(2)     COMPC(3)  COMPC(7)  COMPC(8)
        0.000001         0.00001         0         0         0
CC  IOW=0 water wet, =1 oil wet, =2 mixed wet
CC 3.4.99 CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*---- ICPC    IEPC   IOW
      0       0      0
CC    CPC = 0 for no capillary pressure
CC 3.4.100 CAPILLARY PRESSURE PARAMETER, CPC0
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*---- CPC0
      0
CC
CC 3.4.103 CAPILLARY PRESSURE PARAMETER, EPC0
*---- EPC0
      4.0
CC
CC 3.4.117 MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 1
*---- D(KC,1),KC=1,N
        0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
CC
CC 3.4.118 MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 2
*---- D(KC,2),KC=1,N
        0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
CC
CC 3.4.119 MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 3
*---- D(KC,3),KC=1,N
        0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
CC
CC 3.4.121 LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*---- ALPHAL(1)     ALPHAT(1)
        2           1
CC
CC 3.4.122 LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*---- ALPHAL(2)     ALPHAT(2)
        2           1
CC
CC 3.4.124 LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*---- ALPHAL(3)     ALPHAT(3)
        2           1
CC
CC 3.4.125 flag to specify organic adsorption calculation
*---- iadso=0 if organic adsorption is not considered
       0
CC
CC 3.4.130 SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*---- AD31    AD32     B3D    AD41    AD42   B4D    IADK  IADS1   FADS   REFK
      2.7      0.1    1000.      2   0.    100.       0       0     0   00.
CC
CC 3.4.131 PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*---- QV      XKC     XKS     EQW
     0     0.0    0.0       0.
CC
CC 3.4.132 TRACER PARTITIONING COEFFICIENT (TK(IT),IT=1,NT)
*---- TK(1)
     0.0    0.0      0.0    0.0      0.0     0.0      0.0    0.0      0.0    0.0      0.0     0.0
CC
CC 3.4.133 SALINITY DEPENDENCE PART. COEFF.
*---- TKS(1) TKS(2) TKS(3) TKS(4)    TKS(5)   TKS(6)  TKS(7) TKS(8)  TKS(9)  TKS(10)    TKS(11)
TKS(12)  c5ref
     0.0    0.0      0.0    0.0      0.0     0.0      0.0    0.0      0.0     0.0       0.0       0.0      0.0
CC
```

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CC RADIACTIVE DECAY COEFFICIENT (RDC(IT),IT=1,NT)
*---- RDC(1)
       0  0  0  0  0  0  0  0  0  0  0  0
CC
CC TRACER RETARDATION COEFFICIENT (RET(IT),IT=1,NT)
*---- RET(1)
       0  0  0  0  0  0  0  0  0  0  0  0
CC
CC*****************************************************************
CC                                                    *
CC    3.7 WELL DATA                                   *
CC                                                    *
CC*****************************************************************
CC
CC
CC 3.7.1 FLAG FOR SPECIFIED BOUNDARY AND ZONE IS MODELED
*---- IBOUND     IZONE
      0      0
CC 3.7.5 TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT
NO.
CC     IRO=2 for Peaceman.  ITIME=0 for days; =1 for CN for min&max tstep size
*---- NWELL   IRO    ITIME    NWREL
      31      2       1        31
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   IFIRST   ILAST   IPRF
     1    22     18       2     0.3      -2      3        1      9      0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM31
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
CC  if ICHEK = 0 then no check for limits
*---- ICHEK     PWFMIN     PWFMAX    QTMIN    QTMAX
      0          0        9999.      0        -9999.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   IFIRST   ILAST   IPRF
     2    32     18       2     0.3      -2      3        1      9      0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM42
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
CC  if ICHEK = 0 then no check for limits
*---- ICHEK     PWFMIN     PWFMAX    QTMIN    QTMAX
      0          0        9999.      0        -4492.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
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*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   IFIRST   ILAST   IPRF
      3    41    18      2    0.3      -2     3        1      9     0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM44
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
CC  if ICHEK = 0 then no check for limits
*---- ICHEK     PWFMIN     PWFMAX    QTMIN    QTMAX
       0         0       9999.     0       -4492.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     4     22    27    2    0.3      -2       3      1      9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM45
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     5     32    27     2    0.3      -2       3     1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM46
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     6     42    26    2    0.3     -2       3     1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM47
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
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*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     7      18    14    1       0.3      -2       3     1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF01
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     8      27    13    1       0.3      -2       3     1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF02
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     9      36    13    1       0.3      -2       3     1        9     0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF03
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     10     46    13    1       0.3      -2       3     1        9     0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF04
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
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*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     11     18    23    1        0.3      -2       3      1         9     0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF05
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0        3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     12     27    23    1        0.3      -2       3      1         9     0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF06
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0        3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     13     36    23    1        0.3      -2       3      1         9     0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF07
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0        3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     14     46    21    1        0.3      -2       3      1         9     0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF08
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN       QTMAX
       0          0         6000.      0        3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
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*---- IDW   IW   JW   IFLAG   RW    SWELL   IDIR   ZFIRST   ZLAST   IPRF
    15    16   31   1       0.3     -2       3     1        9    0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF09
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
      0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW   IW   JW   IFLAG   RW    SWELL   IDIR   ZFIRST   ZLAST   IPRF
    16    27   32   1       0.3     -2       3     1        9    0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF10
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
      0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW   IW   JW   IFLAG   RW    SWELL   IDIR   ZFIRST   ZLAST   IPRF
    17    36   32   1       0.3     -2      3     1        9    0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF11
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
      0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW   IW   JW   IFLAG   RW    SWELL   IDIR   ZFIRST   ZLAST   IPRF
    18    45   32   1       0.3     -2       3     1        9    0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
BCF12
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
      0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
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*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     19     12    26    1       0.3      -2       3      1        9       1
cc
cc  3.7.6.b =0 for not perforated, =1 for perforated in this layer
*kpr  1  2  3  4  5  6  7  8  9
     1  0  0  0  1  1  1  1  1
CC
CC 3.7.6c WELL NAME
*----  WELNAM
iDD6
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0          0         6000.      0        3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     20     54    15    1       0.3      -2       3      1        9       1
cc
cc  3.7.6.b =0 for not perforated, =1 for perforated in this layer
*kpr  1  2  3  4  5  6  7  8  9
     1  1  1  1  0  1  1  1  1
CC
CC 3.7.6c WELL NAME
*----  WELNAM
iGG7
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0          0         6000.      0        3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     21     13    14    1       0.3      -2       3      1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
iD7
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0          0         6000.      0        3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   IFIRST   ILAST   IPRF
      22    16    36      4     0.3      -2      3        1     9      1
cc
cc  3.7.6.b =0 for not perforated, =1 for perforated in this layer
*kpr  1  2  3  4  5  6  7  8  9
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    0  0  0  0  1  1  1  1  1
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM23
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
CC  if ICHEK = 0 then no check for limits
*---- ICHEK     PWFMIN     PWFMAX    QTMIN    QTMAX
       0          0        9999.      0        -9999.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   IFIRST   ILAST   IPRF
      23    33    40       4     0.3      -2      3         1      9      1
cc
cc  3.7.6.b =0 for not perforated, =1 for perforated in this layer
*kpr  1  2  3  4  5  6  7  8  9
    0  0  0  0  1  1  1  1  1
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM28
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
CC  if ICHEK = 0 then no check for limits
*---- ICHEK     PWFMIN     PWFMAX    QTMIN    QTMAX
       0          0        9999.      0        -9999.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   IFIRST   ILAST   IPRF
      24    41    21       4     0.3      -2      3         1      9      0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM30
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
CC  if ICHEK = 0 then no check for limits
*---- ICHEK     PWFMIN     PWFMAX    QTMIN    QTMAX
       0          0        9999.      0        -9999.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   IFIRST   ILAST   IPRF
      25    43    5       4     0.3      -2      3         1      9      1
cc
cc  3.7.6.b =0 for not perforated, =1 for perforated in this layer
*kpr  1  2  3  4  5  6  7  8  9
    0  0  0  0  1  1  1  1  1
CC
CC 3.7.6c WELL NAME
*----  WELNAM
pM32
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CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
CC  if ICHEK = 0 then no check for limits
*---- ICHEK     PWFMIN     PWFMAX    QTMIN    QTMAX
       0         0       9999.     0       -9999.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     26    1    10    2       0.3     0       3      1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
WB1
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     27    1    30    2       0.3     0       3      1        9    0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
WB2
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     28   1     40    2       0.3     0       3      1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
WB3
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
       0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     29    75    20    2       0.3     0       3      1        9       1
cc
cc  3.7.6.b =0 for not perforated, =1 for perforated in this layer
*kpr  1  2  3  4  5  6  7  8  9
     1  1  1  1  0  1  1  1  1
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CC
CC 3.7.6c WELL NAME
*----  WELNAM
EB1
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
      0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     30    75    36    2       0.3      0       3     1        9       0
CC
CC 3.7.6c WELL NAME
*----  WELNAM
EB2
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
      0         0        6000.     0       3370.
CC 3.7.6a WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS,
SKIN
CC     IFLAG =1QInj,=2PresProd,=3PresInj=4Qprod,IDIR =3for vert. well
*---- IDW    IW    JW    IFLAG    RW     SWELL   IDIR   ZFIRST   ZLAST   IPRF
     31    73    49    2       0.3      0       3     1        9       1
cc
cc  3.7.6.b =0 for not perforated, =1 for perforated in this layer
*kpr  1  2  3  4  5  6  7  8  9
     0  1  1  1  1  1  1  1  1
CC
CC 3.7.6c WELL NAME
*----  WELNAM
EB3
CC  if ICHEK = 0 then no check for limits
CC 3.7.6d ICHEK , MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE in CFD
*---- ICHEK     PWFMIN     PWFMAX    QTMIN      QTMAX
      0         0        6000.     0       3370.
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=1 OR 4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
      1       25
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=1 OR 4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
      2       25
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=1 OR 4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
      3       25
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=1 OR 4)
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*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
     4       25
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=1 OR 4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
     5       25
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=1 OR 4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
     6       25
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
         tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
         7       700     0.99    0       0.01    0.23    0.455   0       0       0       1
         0       0       0       0       0       0       0       0       0       0       0
         7       0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         7       0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----    ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
         tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
         8       700     0.99    0       0.01    0.23    0.455   0       0       0       1
         0       0       0       0       0       0       0       0       0       0       0
         8       0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         8       0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
         tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
         9       700     0.99    0       0.01    0.23    0.455   0       0       0       1
         0       0       0       0       0       0       0       0       0       0       0
         9       0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         9       0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
         tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
         10      700     0.99    0       0.01    0.23    0.455   0       0       0       1
         0       0       0       0       0       0       0       0       0       0       0
         10      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         10      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
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 *----   ID    QI(M,L) water  oil    surf   polymer Chlor  divalent al1   al2    tr1
         tr2   tr3     tr4    tr5    tr6    tr7     tr8    tr9      tr10  tr11   tr12
         11    700     0.99   0      0.01   0.23    0.455  0        0     0      1
         0     0       0      0      0      0       0      0        0     0      0
         11    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
         11    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID    QI(M,L) water  oil    surf   polymer Chlor  divalent al1   al2    tr1
         tr2   tr3     tr4    tr5    tr6    tr7     tr8    tr9      tr10  tr11   tr12
         12    700     0.99   0      0.01   0.23    0.455  0        0     0      1
         0     0       0      0      0      0       0      0        0     0      0
         12    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
         12    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
         *---- ID      QI(M,L) water  oil    surf    polymer Chlor    divalent al1  al2
         tr1   tr2     tr3    tr4    tr5    tr6     tr7    tr8      tr9   tr10   tr11
         tr12
         13    700     0.99   0      0.01   0.23    0.455  0        0     0      1
         0     0       0      0      0      0       0      0        0     0      0
         13    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
         13    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID    QI(M,L) water  oil    surf   polymer Chlor  divalent al1   al2    tr1
         tr2   tr3     tr4    tr5    tr6    tr7     tr8    tr9      tr10  tr11   tr12
         14    700     0.99   0      0.01   0.23    0.455  0        0     0      1
         0     0       0      0      0      0       0      0        0     0      0
         14    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
         14    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID    QI(M,L) water  oil    surf   polymer Chlor  divalent al1   al2    tr1
         tr2   tr3     tr4    tr5    tr6    tr7     tr8    tr9      tr10  tr11   tr12
         15    700     0.99   0      0.01   0.23    0.455  0        0     0      1
         0     0       0      0      0      0       0      0        0     0      0
         15    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
         15    0       0      0      0      0       0      0        0     0      0
         0     0       0      0      0      0       0      0        0     0      0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
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 *----    ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1     al2     tr1
          tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
          16      700     0.99    0       0.01    0.23    0.455   0       0       0       1
          0       0       0       0       0       0       0       0       0       0       0
          16      0       0       0       0       0       0       0       0       0       0
          0       0       0       0       0       0       0       0       0       0       0
          16      0       0       0       0       0       0       0       0       0       0
          0       0       0       0       0       0       0       0       0       0       0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----    ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1     al2     tr1
          tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
          17      700     0.99    0       0.01    0.23    0.455   0       0       0       1
          0       0       0       0       0       0       0       0       0       0       0
          17      0       0       0       0       0       0       0       0       0       0
          0       0       0       0       0       0       0       0       0       0       0
          17      0       0       0       0       0       0       0       0       0       0
          0       0       0       0       0       0       0       0       0       0       0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----    ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1     al2     tr1
          tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
          18      700     0.99    0       0.01    0.23    0.455   0       0       0       1
          0       0       0       0       0       0       0       0       0       0       0
          18      0       0       0       0       0       0       0       0       0       0
          0       0       0       0       0       0       0       0       0       0       0
          18      0       0       0       0       0       0       0       0       0       0
          0       0       0       0       0       0       0       0       0       0       0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----  ID    QI(M,L) water   oil  surf  polymer Chlor  divalent   al1  al2  tr1 tr2 tr3 tr4   tr5   tr6   tr7 tr8 tr9
tr10   tr11   tr12
      19    0    1      0    0     0     0.336   0.0641    0    0    0   0   0   0    0     0    0   0   0    0     0     0
      19     0     0      0    0     0     0      0        0    0    0   0   0   0    0     0    0   0   0    0     0     0
      19     0     0      0    0     0     0      0        0    0    0   0   0   0    0     0    0   0   0    0     0     0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----  ID    QI(M,L) water oil  surf  polymer Chlor   divalent   al1  al2  tr1 tr2 tr3 tr4   tr5   tr6   tr7 tr8 tr9
tr10   tr11  tr12
      20    0    1      0    0     0     0.336   0.0641    0    0    0   0   0   0    0     0    0   0   0    0     0     0
      20     0     0      0    0     0     0      0        0    0    0   0   0   0    0     0    0   0   0    0     0     0
      20     0     0      0    0     0     0      0        0    0    0   0   0   0    0     0    0   0   0    0     0     0
CC    FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----  ID    QI(M,L) water oil  surf  polymer  Chlor  divalent   al1  al2  tr1 tr2 tr3 tr4   tr5   tr6   tr7 tr8 tr9
tr10   tr11   tr12
      21   0    1      0    0     0     0.336   0.0641    0    0    0   0   0   0    0     0    0   0   0    0     0     0
      21     0     0      0    0     0     0      0        0    0    0   0   0   0    0     0    0   0   0    0     0     0
      21     0     0      0    0     0     0      0        0    0    0   0   0   0    0     0    0   0   0    0     0     0
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
```

```
      22        -5.6
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
      23        -5.6
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
      24        -5.6
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----  ID      For IFLAG =4, specified RATE in CFD, negative for prodcution
      25        -5.6
CC   IFLAG = 2
CC 3.7.7b ID, Pressure constrained boundary well
*----  ID      pressure in psi
      26      350.
CC   IFLAG = 2
CC 3.7.7b ID, Pressure constrained boundary well
*----  ID      pressure in psi
      27      370.
CC   IFLAG = 2
CC 3.7.7b ID, Pressure constrained boundary well
*----  ID      pressure in psi
      28      350.
CC   IFLAG = 2
CC 3.7.7b ID, Pressure constrained boundary well
*----  ID      pressure in psi
      29      320.
CC   IFLAG = 2
CC 3.7.7b ID, Pressure constrained boundary well
*----  ID      pressure in psi
      30      340.
CC   IFLAG = 2
CC 3.7.7b ID, Pressure constrained boundary well
*----  ID      pressure in psi
      31      320.
CC      3.7.8     CUM.     INJ.     TIME    ,        AND     INTERVALS     (DAY)   FOR
        WRITING            TO       OUTPUT           FILES

CC      profilesPROF       prodPROF         prodHIST         maps     recovery
*----   TINJ      CUMPR1            CUMHI1           WRHPV            WRPRF RSTC
        120       60       60       5       30       60
CC********************************************************* Inject SP for 120 days
*********************************************************
CC      3.7.11    FOR      IMES=2 ,THE      INI.     TIME     STEP,CONC.
        TOLERANCE,MAX.,MIN.         courant  numbers
*----   DT        DCLIM  CNMAX      CNMIN
        0.00001 0.001    0.05     0.001
CC********************************************* inject     Polymer Drive     300     days
        **************************************************
CC      FLAG      FOR      INDICATING      BOUNDARY      CHANGE
```

```
*----   IBMOD
        0
CC
CC      IRO,    ITIME,  NEW     FLAGS   FOR     ALL     THE     WELLS

*----   IRO     ITIME   IFLAG
        2       1       6*2     15*1    4*4     6*2
CC
CC      NUMBER          OF      WELLS   CHANGES         IN      LOCATION        OR      SKIN
        OR      PWF
*----   NWEL1
        0
CC
CC      NUMBER          OF      WELLS   WITH    RATE    CHANGES,        ID
*----   NWEL2   ID
        12      7       8       9       10      11      12      13      14      15      16
        17      18
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        7       700     1       0       0       0.295   0.2665  0       0       0       0
        1       0       0       0       0       0       0       0       0       0       0
        7       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        7       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        8       700     1       0       0       0.295   0.2665  0       0       0       0
        1       0       0       0       0       0       0       0       0       0       0
        8       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        8       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        9       700     1       0       0       0.295   0.2665  0       0       0       0
        1       0       0       0       0       0       0       0       0       0       0
        9       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        9       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
```

```
          10    700      1     0    0    0.295    0.2665   0    0    0    0
          1     0        0     0    0    0        0        0    0    0    0
          10    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
          10    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----    ID    QI(M,L)  water oil  surf polymer  Chlor    divalent al1 al2 tr1
          tr2   tr3      tr4   tr5  tr6  tr7      tr8      tr9  tr10 tr11 tr12
          11    700      1     0    0    0.295    0.2665   0    0    0    0
          1     0        0     0    0    0        0        0    0    0    0
          11    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
          11    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----    ID    QI(M,L)  water oil  surf polymer  Chlor    divalent al1 al2 tr1
          tr2   tr3      tr4   tr5  tr6  tr7      tr8      tr9  tr10 tr11 tr12
          12    700      1     0    0    0.295    0.2665   0    0    0    0
          1     0        0     0    0    0        0        0    0    0    0
          12    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
          12    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----    ID    QI(M,L)  water oil  surf polymer  Chlor    divalent al1 al2 tr1
          tr2   tr3      tr4   tr5  tr6  tr7      tr8      tr9  tr10 tr11 tr12
          13    700      1     0    0    0.295    0.2665   0    0    0    0
          1     0        0     0    0    0        0        0    0    0    0
          13    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
          13    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----    ID    QI(M,L)  water oil  surf polymer  Chlor    divalent al1 al2 tr1
          tr2   tr3      tr4   tr5  tr6  tr7      tr8      tr9  tr10 tr11 tr12
          14    700      1     0    0    0.295    0.2665   0    0    0    0
          1     0        0     0    0    0        0        0    0    0    0
          14    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
          14    0        0     0    0    0        0        0    0    0    0
          0     0        0     0    0    0        0        0    0    0    0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----    ID    QI(M,L)  water oil  surf polymer  Chlor    divalent al1 al2 tr1
          tr2   tr3      tr4   tr5  tr6  tr7      tr8      tr9  tr10 tr11 tr12
          15    700      1     0    0    0.295    0.2665   0    0    0    0
          1     0        0     0    0    0        0        0    0    0    0
```

```
         15      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         15      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
         tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
         16      700     1       0       0       0.295   0.2665  0       0       0       0
         1       0       0       0       0       0       0       0       0       0       0
         16      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         16      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
         tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
         17      700     1       0       0       0.295   0.2665  0       0       0       0
         1       0       0       0       0       0       0       0       0       0       0
         17      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         17      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
         tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
         18      700     1       0       0       0.295   0.2665  0       0       0       0
         1       0       0       0       0       0       0       0       0       0       0
         18      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
         18      0       0       0       0       0       0       0       0       0       0
         0       0       0       0       0       0       0       0       0       0       0
CC       3.7.8   CUM.    INJ.    TIME    ,       AND     INTERVALS       (DAY)   FOR
         WRITING         TO      OUTPUT          FILES

CC       profilesPROF    prodPROF        prodHIST        maps    recovery
*----    TINJ    CUMPR1          CUMHI1          WRHPV           WRPRF RSTC
         420     60      60      5       60      60
CC
CC       3.7.11  FOR     IMES=2 ,THE     INI.    TIME    STEP,CONC.
         TOLERANCE,MAX.,MIN.             courant numbers
*----    DT      DCLIM   CNMAX           CNMIN
         0.00001 0.001   0.1     0.002
CC*************************************** inject  Post-Water      Flush   for     421
         days    *********************************************************
CC       FLAG    FOR     INDICATING      BOUNDARY        CHANGE
*----    IBMOD
         0
CC
```

```
CC      IRO,    ITIME,  NEW     FLAGS   FOR     ALL     THE     WELLS
*----   IRO     ITIME   IFLAG
        2       1       6*2     15*1    4*4     6*2

CC
CC      NUMBER          OF      WELLS   CHANGES         IN      LOCATION        OR      SKIN
        OR      PWF
*----   NWEL1
        0
CC
CC      NUMBER          OF      WELLS   WITH    RATE    CHANGES,        ID
*----   NWEL2   ID

        12      7       8       9       10      11      12      13      14      15      16
        17      18
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        7       700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
7       0       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0

        7       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        8       700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        8       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        8       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        9       700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        9       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        9       0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        10      700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
```

```
        10      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        10      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        11      700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        11      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        11      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        12      700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        12      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        12      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        13      700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        13      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        13      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----   ID      QI(M,L) water   oil     surf    polymer Chlor   divalent al1    al2     tr1
        tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11    tr12
        14      700     1       0       0       0       0.1811  0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        14      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        14      0       0       0       0       0       0       0       0       0       0
        0       0       0       0       0       0       0       0       0       0       0
CC   FOR IFLAG = 3, pressure controlled injector
CC  3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
        *----   ID      QI(M,L) water   oil     surf    polymer Chlor   dival   al1     al2
        tr1     tr2     tr3     tr4     tr5     tr6     tr7     tr8     tr9     tr10    tr11
        tr12    15      700     1       0       0       0       0.1811  0       0       0
        0       0       0       0       0       0       0       0       0       0       0
        0
```

	15	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	15	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
CC FOR IFLAG = 3, pressure controlled injector											
CC 3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)											
*----	ID	QI(M,L)	water	oil	surf	polymer	Chlor	divalent	al1	al2	tr1
	tr2	tr3	tr4	tr5	tr6	tr7	tr8	tr9	tr10	tr11	tr12
	16	700	1	0	0	0	0.1811	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	16	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	16	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
CC FOR IFLAG = 3, pressure controlled injector											
CC 3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)											
*----	ID	QI(M,L)	water	oil	surf	polymer	Chlor	divalent	al1	al2	tr1
	tr2	tr3	tr4	tr5	tr6	tr7	tr8	tr9	tr10	tr11	tr12
	17	700	1	0	0	0	0.1811	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	17	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	17	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
CC FOR IFLAG = 3, pressure controlled injector											
CC 3.7.7a ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)											
*----	ID	QI(M,L)	water	oil	surf	polymer	Chlor	divalent	al1	al2	tr1
	tr2	tr3	tr4	tr5	tr6	tr7	tr8	tr9	tr10	tr11	tr12
	18	700	1	0	0	0	0.1811	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	18	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	18	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
CC	3.7.8	CUM.	INJ.	TIME	,	AND	INTERVALS		(DAY)	FOR	
	WRITING		TO	OUTPUT		FILES					
CC	profilesPROF		prodPROF		prodHIST		maps	recovery*----		TINJ	
	CUMPR1		CUMHI1		WRHPV		WRPRF	RSTC			
	720	60	60	5	60	150					
CC											
CC	3.7.11	FOR	IMES=2	,THE	INI.	TIME	STEP,CONC.				
	TOLERANCE,MAX.,MIN.				courant	numbers					
*----	DT	DCLIM	CNMAX		CNMIN						
	0.00001	0.001	0.1	0.001							

Appendix B: Input File for Base Case in Chapter 4 (Fine Grid)

```
        ************************************************************************
CC                                              *
CC    BRIEF DESCRIPTION OF DATA SET : UTCHEM (VERSION 9.95)                    *
CC                                              *
CC**********************************************************************
CC                                              *
CC      Surfactant Flood Pilot Evaluation                   *
CC                                              *
CC  LENGTH (FT) :39600'            PROCESS : S/SP             *
CC  THICKNESS (FT) :4150'           PRESSURE (i) CONSTRAINTS           *
CC  WIDTH (FT) :2' avg, varies      COORDINATES : CARTESIAN              *
CC  POROSITY : varies,              DAY SPECIFICATION                *
CC  GRID BLOCKS : 198x83x4=65736    COURANT NUMBER SPECIFICATION        *
CC  NON-UNIFORM GRIDBLOCK SIZES     WELL SKIN = 0                      *
CC                                                   *
CC**********************************************************************
CC                                              *
CC**********************************************************************
CC                                              *
CC    RESERVOIR DESCRIPTION                             *
CC                                              *
CC**********************************************************************
CC
CC Run number
*---- RUNNO
COP14a
CC
CC Title and run description
*---- title(i)
COP14a
CC
CC
CC
CC SIMULATION FLAGS: IMODE = 1 for new case, IMODE=2 for restart
*---- IMODE IMES IDISPC ICWM ICAP IREACT IBIO ICOORD ITREAC ITC  IGAS  IENG  IDUAL
ITENS
     1    3    3    0    0    0    0    1    0    0    0    0    0    0
CC
CC no. of gridblocks,flag specifies constant or variable grid size,unit
*---- NX    NY    NZ  IDXYZ  IUNIT
    126   97    4    2     0
CC
CC VARIABLE GRID SIZE ON A REGIONAL BASIS IN X DIRECTION
*---- II1, II2, DX1
        126*100
CC
CC VARIABLE GRID SIZE ON A REGIONAL BASIS IN Y DIRECTION
*---- JJ1, JJ2, DY1
```

```
        56*50  21*16.67 20*50
CC
CC CONSTANT GRID SIZE IN Z DIRECTION
*---- KK1, KK2, DZ1
        2.04
        2.04
        4.12
        4.12
CC
CC total no. of components,no. of tracers,no. of gel components
*----n    no    ntw    nta    ngc    ng    noth
   10    0      2     0      0      0       0
CC
CC Name of the components
*----spname(i) for i=1 to n
Water
Oil
Surf.
Polymer
Chloride
Calcium
Alcohol1
Alcohol2
Tracer1
Tracer2
CC
CC flag indicating if the component is included in calculations or not
*----icf(kc) for kc=1,n
   1  1  1  1  1  1  0  0 0  0
CC
CC*******************************************************************
CC                                        *
CC  3.2  OUTPUT OPTIONS                           *
CC                                        *
CC*******************************************************************
CC
CC  ISTOP=0 for TMAX & TINJ in days, =1 for PV; ICUM=0 for output in days, =1 for PV
CC 3.2.1 FLAG TO WRITE TO UNIT 3,FLAG FOR PV OR DAYS TO PRINT OR TO STOP THE RUN
*---- ICUMTM  ISTOP  IOUTGMS
    0      0      0
CC
CC 3.2.2 FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*---- IPRFLG(KC),KC=1,N
   1  1  1  1  1  1  0  0 0  0
CC
CC 3.2.3 FLAG FOR PRES.,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE
PROFILES
*---- IPPRES IPSAT IPCTOT IPBIO IPCAP IPGEL IPALK IPTEMP IPOBS
    1     1     1     0     0     0     0     0     0
CC
CC 3.2.4 FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 4 (Prof)
*---- ICKL IVIS IPER ICNM ICSE IHYSTP IFOAMP INONEQ
```

```
     1    1    0    0    1      0      0      0
CC
CC 3.2.5 FLAG  for variables to PROF output file
*---- IADS IVEL IRKF IPHSE
     1    0    1    0
CC
CC*****************************************************************
CC                                                   *
CC  3.3      RESERVOIR PROPERTIES                                 *
CC                                                   *
CC*****************************************************************
CC
CC
CC 3.3.1 MAX. SIMULATION TIME (days)
*---- TMAX
    6000
CC
CC 3.3.2 ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*---- COMPR               PSTAND
    0.000001            4000
CC  IMOD =0
CC 3.3.3 FLAG FOR CONSTANT OR VARIABLE POR, PERM. & RESERVOIR PROPERTY
MODIFICATION
*---- IPOR1  IPERMX IPERMY IPERMZ IMOD  ITRANZ  INTG
      4     4     3     3    0       1    0
CC
CC 3.3.13 Y DIRECTION PERMEABILITY IS DEPENDENT ON X DIRECTION PERMEABILITY
*---- FACTY,   CONSTANT PERMEABILITY MULTIPLIER FOR Y DIRECTION PERMEABILITY
      1
CC
CC 3.3.17 Z DIRECTION PERMEABILITY IS DEPENDENT ON X DIRECTION PERMEABILITY
*---- FACTZ, CONSTANT PERMEABILITY MULTIPLIER FOR Z DIRECTION PERMEABILITY
     0.25
CC
CC 3.3.18 FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER
SATURATION,INITIAL AQUEOUS PHASE cOMPOSITIONS
*----IDEPTH  IPRESS  ISWI  ICWI
     4       4      4     -1
CC
CC 3.3.52 BRINE SALINITY AND DIVALENT CATION CONCENTRATION (MEQ/ML)
*---- C50       C60
   1.055     0.102
CC
CC*****************************************************************
CC                                                   *
CC    3.4 PHYSICAL PROPERTY DATA                                  *
CC                                                   *
CC*****************************************************************
CC
CC 3.4.1 OIL CONC. AT PLAIT POINT FOR TYPE II(+)AND TYPE II(-), CMC
CC                   CMC
*---- c2plc  c2prc   epsme   ihand
```

```
       0      1     0.0001     0
CC
CC 3.4.2 flag indicating type of phase behavior parameters
*---- ifghbn=0 for input height of binodal curve; =1 for input sol. ratio
       0
CC 3.4.3 SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*---- hbns70   hbnc70   hbns71   hbnc71   hbns72   hbnc72
       0    0.02       0     0.014     0     0.03
CC 3.4.5 SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*---- hbns80  hbnc80  hbns81  hbnc81  hbns82  hbnc82
       0       0       0       0       0       0
CC
CC 3.4.6 LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*---- csel7   cseu7   csel8   cseu8
     0.715   0.86    0.      0.
CC 3.4.7 THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
CC    Ca     Alcohol#1  Alcohol#2
*---- beta6    beta7    beta8
       0.0        0       0
CC
CC 3.4.8 FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*---- ialc   opsk7o   opsk7s   opsk8o   opsk8s
       0      0        0        0        0
CC  these are used only for alcohol partitioning in a two alcohol system:
CC 3.4.9 NO. OF ITERATIONS, AND TOLERANCE
*---- nalmax     epsalc
       20       0.0001
CC 3.4.10 ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
CC   aq-oleic   aq-oleic  surf-oleic
*---- akwc7     akws7     akm7       ak7      pt7
      4.671    1.79       48       35.31    0.222
CC
CC 3.4.11 ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*---- akwc8     akws8    akm8    ak8     pt8
       0         0        0      0       0
CC
CC 3.4.22 ift model flag
*----  ift=0 for Healy&Reed; =1 for Chun Huh correl.
       1
CC 3.4.24 INTERFACIAL TENSION PARAMETERS
CC    typ=.1-.35   typ=5-20
*---- chuh         ahuh
     0.3           10
CC 3.4.25 LOG10 OF OIL/WATER INTERFACIAL TENSION
CC     units of log 10 dynes/cm = mN/m, 25.98 dynes/cm - from Eclipse
*---- xiftw
      1.415
CC 3.4.26 ORGANIC MASS TRANSFER FLAG
CC    imass=0 for no oil sol. in water.  icorr=0 for constant MTC
*---- imass   icor
```

```
       0       0
cc
cc
*--- IWALT    IWALF
      0       0
CC 3.4.31 CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3 NEED LAB
DATA
CC              AQ     OLEIC     ME
*---- itrap      t11     t22      t33
       2        1865   10000    364.2
CC    iperm=0 for constant; =1 varies by layer; =2 varies by gridblock
CC  3.4.32 FLAG FOR RELATIVE PERMEABILITY AND CAPILLARY PRESSURE MODEL
*---- iperm         irtype
       0             0
CC
CC 3.4.35 FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*---- isrw    iprw    iew
       1      1       1
CC
CC 3.4.38 CONSTANT RESIDUAL WATER SATURATION FOR EACH LAYER AT LOW
CAPILLARY NO.
*---- S1RW(K) FOR K=1 TO 4
            2*0.05   4*0.05
CC
CC 3.4.39 CONSTANT RESIDUAL OIL SATURATION FOR EACH LAYER AT LOW CAPILLARY
NO.
*---- S2RW(K) FOR K=1 TO 4
            2*0.208 4*0.232
CC
CC 3.4.40 CONSTANT RESIDUAL MICROEMULSION SATURATION FOR EACH LAYER AT LOW
CAPILLARY NO.
*---- S2RW(K) FOR K=1 TO 4
            2*0.05   4*0.05
CC
CC 3.4.45 CONSTANT END-POINT REL. PERM. OF WATER FOR EACH LAYER AT LOW
CAPILLARY NO.
*---- P1RW(K) FOR K=1 TO 4
            2*0.28   4*0.25
CC
CC 3.4.46 CONSTANT END-POINT REL. PERM. OF OIL FOR EACH LAYER AT LOW CAPILLARY
NO.
*---- P2RW(K) FOR K=1 TO 4
            2*0.675     4*0.61
CC
CC 3.4.45 CONSTANT END-POINT REL. PERM. OF MICROEMULSION FOR EACH LAYER AT
LOW CAPILLARY NO.
*---- P3RW(K) FOR K=1 TO 4
            2*0.28   4*0.25
CC
CC 3.4.52 CONSTANT REL. PERM. EXPONENT OF WATER FOR EACH LAYER AT LOW
CAPILLARY NO.
*---- E1WC(K) FOR K=1 TO 4
```

```
           2*3.2   4*3.0
CC
CC 3.4.53 CONSTANT REL. PERM. EXPONENT OF OIL FOR EACH LAYER AT LOW CAPILLARY
NO.
*---- E2WC(K) FOR K=1 TO 4
           2*3.3   4*2.1
CC
CC 3.4.54 CONSTANT REL. PERM. EXPONENT OF MICROEMULSION FOR EACH LAYER AT
LOW CAPILLARY NO.
*---- E3WC(K) FOR K=1 TO 4
           2*3.2     4*3.0
CC
CC 3.4.62 RES. SATURATION OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*---- s1rc   s2rc   s3rc
      0     0.01      0
CC
CC 3.4.63 ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*---- p1rc   p2rc   p3rc
      1     1     1
CC
CC 3.4.64 REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*---- e13c   e23c   e31c
      1     1     1
CC
CC 3.4.65 WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*---- VIS1      VIS2      TSTAND
     0.3     1.732      0
CC
CC 3.4.85 COMPOSITIONAL PHASE VISCOSITY PARAMETERS FOR MICROEMULSION NEED
LAB DATA
*----   ALPHAV1   ALPHAV2   ALPHAV3   ALPHAV4  ALPHAV5
         1.5        1.5       0.1       0.1     0.1
CC
CC 3.4.86 PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*---- AP1      AP2      AP3
      8       40      5
CC
CC 3.4.87 PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG
CSEP
*---- BETAP    CSE1     SSLOPE
      1      0.01     -0.2
CC
CC 3.4.88 PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*---- GAMMAC   GAMHF   POWN   ipmod    ISHEAR   RWEFF  GAMHF2
      130      1500    1.7      0       1       2.0    0.0
CC
CC 3.4.90  FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*---- IPOLYM    EPHI3    EPHI4    BRK     CRK   rkcut
      1        1         1      100    0.015     10
CC 3.4.92 SPECIFIC WEIGHT FOR COMPONENTS 1,2,23,3, Coeffient of oil and GRAVITY FLAG
CC   Values obtained from Eclipse Data file.
*---- DEN1     DEN2      DEN23    DEN3      DEN7    DEN8     IDEN
```

```
     0.464    0.38     0.38    0.464      0.346     0      2
CC   ISTB=0:BOTTOMHOLE CONDITION , 1: STOCK TANK
CC 3.4.99 FLAG FOR CHOICE OF UNITS when printing
*----- ISTB
       0
CC Water compressibility from Eclipse Data file, Oil compressiblity from Eclipse PVT tables
CC 3.4.101 COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----   COMPC(1)       COMPC(2)      COMPC(3)    COMPC(7)  COMPC(8)
      0.00000249      0.00000805    0.0000         0         0
CC
CC 3.4.105 CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE
FLAG
*---- ICPC    IEPC   IOW
      1      1      0
CC    CPC = 0 for no capillary pressure
CC 3.4.107 CAPILLARY PRESSURE PARAMETER, CPCK, FOR EACH LAYER
*---- CPCK
      2*0.20 4*0.21
CC
CC 3.4.109 CAPILLARY PRESSURE PARAMETER, EPCK, FOR EACH LAYER
*---- EPCK
      2*0.36 4*0.28
CC
CC 3.4.124 MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 1
*---- D(KC,1),KC=1,N
       0  0  0  0  0  0  0  0 0 0
CC
CC 3.4.125 MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 2
*---- D(KC,2),KC=1,N
       0  0  0  0  0  0  0  0 0 0
CC
CC 3.4.126 MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 3
*---- D(KC,3),KC=1,N
       0  0  0  0  0  0  0  0 0 0
CC
CC 3.4.128 LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*---- ALPHAL(1)     ALPHAT(1)
       0.1           1
CC
CC 3.4.129 LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*---- ALPHAL(2)     ALPHAT(2)
       0.1           1
CC
CC 3.4.130 LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*---- ALPHAL(3)     ALPHAT(3)
       0.1           1
CC
CC 3.4.132 flag to specify organic adsorption calculation
*---- iadso=0 if organic adsorption is not considered
       0
CC
CC 3.4.137 SURFACTANT AND POLYMER ADSORPTION PARAMETERS
```

```
*---- AD31    AD32     B3D    AD41    AD42   B4D   IADK  IADS1   FADS   REFK
      2.7     0.1    1000.     2      0.    100.    0     0       0     00.
CC
CC 3.4.131 PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*---- QV      XKC     XKS     EQW
     0      0.0    0.0        0.
CC
CC 3.4.132 TRACER PARTITIONING COEFFICIENT (TK(IT),IT=1,NT)
*---- TK(1)
     0.0    0.0
CC
CC 3.4.133 SALINITY DEPENDENCE PART. COEFF.
*---- TKS(1) TKS(2) TKS(3) TKS(4)           c5ref
     0.0    0.0      0.0
CC
CC RADIACTIVE DECAY COEFFICIENT (RDC(IT),IT=1,NT)
*---- RDC(1)
       0  0
CC
CC TRACER RETARDATION COEFFICIENT (RET(IT),IT=1,NT)
*---- RET(1)
       0  0
CC*******************************************************************
CC                                                *
CC                                                *
CC    WELL DATA                                            *
CC                                                *
CC*******************************************************************
CC
CC
CC FLAG FOR PRESSURE CONST. BOUNDARIES
*---- IBOUND  IZONE
      0       0
CC
CC TOTAL NO. OF WELLS, WELL RADIUS FLAG, TIME OR COURANT NO
*----NWELL  IRO  ITIME   NWREL

      9    2     1     9
CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW     IW     JW   IFLAG     RW    SWELL   IDIR   KFIRST   KLAST   IPRF
          1          1          10         3          0.25       0          4          1          1          0
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
42
CC
CC
*--------IW     JW     KW    TCON
1           10         1          0.2794
2           10         1          0.2794
1           10         2          2.6021
```

```
2           10          2           2.6021
1           10          2           2.2309
2           10          2           2.2309
3           10          2           4.6806
4           10          2           4.6806
5           10          2           2.2481
6           10          2           2.2481
5           10          2           1.7305
6           10          2           1.7305
7           10          2           2.3785
8           10          2           2.3785
9           10          2           1.7462
10          10          2           1.7462
9           10          2           0.3912
10          10          2           0.3912
11          10          2           0.2300
12          10          2           0.2300
11          10          1           4.3816
12          10          1           4.3816
13          10          1           4.2534
14          10          1           4.2534
15          10          1           0.0859
16          10          1           0.0859
15          10          1           4.0470
16          10          1           4.0470
17          10          1           3.2145
18          10          1           3.2145
17          10          2           0.2984
18          10          2           0.2984
17          10          3           0.0401
18          10          3           0.0401
17          10          3           0.0949
18          10          3           0.0949
19          10          3           0.6770
20          10          3           0.6770
19          10          2           0.0824
20          10          2           0.0824
19          10          1           0.1789
20          10          1           0.1789
CC
CC NAME OF THE WELL
*---- WELNAM
I492R
CC
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE

*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0        0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW      IW      JW   IFLAG      RW    SWELL   IDIR   KFIRST   KLAST   IPRF
          2          11         91         4           0.25       0           4           1           1           0
```

```
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
72
CC
CC
*-------IW      JW      KW
11      91      1       2.3636
12      91      1       2.3636
11      91      2       0.1768
12      91      2       0.1768
13      91      1       1.9886
14      91      1       1.9886
13      91      2       0.9682
14      91      2       0.9682
15      91      2       1.8511
16      91      2       1.8511
17      91      2       2.5317
18      91      2       2.5317
19      91      2       2.0864
20      91      2       2.0864
19      91      2       0.3256
20      91      2       0.3256
21      91      2       2.7669
22      91      2       2.7669
23      91      2       2.5299
24      91      2       2.5299
25      91      2       0.7486
26      91      2       0.7486
25      91      3       0.4782
26      91      3       0.4782
27      91      2       0.6492
28      91      2       0.6492
27      91      2       0.0252
28      91      2       0.0252
27      91      3       1.5848
28      91      3       1.5848
29      91      3       2.0512
30      91      3       2.0512
31      91      3       2.1740
32      91      3       2.1740
33      91      3       2.0495
34      91      3       2.0495
33      91      2       0.1359
34      91      2       0.1359
33      91      1       0.1057
34      91      1       0.1057
33      91      4       0.1287
34      91      4       0.1287
35      91      4       0.0233
36      91      4       0.0233
35      91      4       0.2958
```

```
36   91   4   0.2958
37   91   4   0.1778
38   91   4   0.1778
37   91   3   0.2192
38   91   3   0.2192
37   91   3   1.1267
38   91   3   1.1267
37   91   3   0.1283
38   91   3   0.1283
39   91   3   0.9724
40   91   3   0.9724
39   91   3   0.0969
40   91   3   0.0969
39   91   2   0.5465
40   91   2   0.5465
39   91   1   0.5144
40   91   1   0.5144
41   91   1   0.1269
42   91   1   0.1269
41   91   1   0.4282
42   91   1   0.4282
41   91   2   0.4683
42   91   2   0.4683
41   91   2   0.2013
42   91   2   0.2013
41   91   1   0.4775
42   91   1   0.4775
CC
CC NAME OF THE WELL

*---- WELNAM
P498
CC
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW     IW     JW   IFLAG     RW    SWELL   IDIR   KFIRST   KLAST   IPRF
         3      11     94     3      0.25     0       4       1        1       0
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
152
CC
CC
*-------IW     JW     KW
11   94   1   2.3636
12   94   1   2.3636
11   94   2   0.1768
12   94   2   0.1768
13   94   1   1.9886
```

14	94	1	1.9886
13	94	2	0.9682
14	94	2	0.9682
15	94	2	1.8511
16	94	2	1.8511
17	94	2	2.5317
18	94	2	2.5317
19	94	2	2.0864
20	94	2	2.0864
19	94	2	0.3256
20	94	2	0.3256
21	94	2	2.7669
22	94	2	2.7669
23	94	2	1.5288
24	94	2	1.5288
23	94	3	0.8045
24	94	3	0.8045
25	94	3	0.9211
26	94	3	0.9211
25	94	4	0.6938
26	94	4	0.6938
27	94	4	0.2705
28	94	4	0.2705
27	94	4	0.3284
28	94	4	0.3284
27	94	3	0.9419
28	94	3	0.9419
29	94	3	0.9667
30	94	3	0.9667
29	94	3	0.9269
30	94	3	0.9269
31	94	3	0.5966
32	94	3	0.5966
31	94	3	0.3325
32	94	3	0.3325
31	94	2	1.7839
32	94	2	1.7839
33	94	2	2.1786
34	94	2	2.1786
35	94	2	1.5988
36	94	2	1.5988
35	94	1	0.6096
36	94	1	0.6096
37	94	1	1.0104
38	94	1	1.0104
37	94	1	1.1523
38	94	1	1.1523
37	94	2	0.0571
38	94	2	0.0571
39	94	2	0.7366
40	94	2	0.7366
39	94	1	0.4409

40	94	1	0.4409
39	94	2	0.2732
40	94	2	0.2732
41	94	2	0.5094
42	94	2	0.5094
41	94	3	0.4237
42	94	3	0.4237
41	94	4	0.0772
42	94	4	0.0772
43	94	2	0.9173
44	94	2	0.9173
43	94	1	2.6301
44	94	1	2.6301
45	94	1	2.3151
46	94	1	2.3151
47	94	1	0.4599
48	94	1	0.4599
47	94	2	0.5683
48	94	2	0.5683
47	94	3	0.2395
48	94	3	0.2395
47	94	4	0.3036
48	94	4	0.3036
49	94	4	0.0213
50	94	4	0.0213
49	94	3	0.3017
50	94	3	0.3017
49	94	2	0.3969
50	94	2	0.3969
49	94	1	1.4084
50	94	1	1.4084
51	94	1	0.0991
52	94	1	0.0991
51	94	2	1.3426
52	94	2	1.3426
53	94	2	0.2750
54	94	2	0.2750
53	94	2	0.6786
54	94	2	0.6786
55	94	2	1.9519
56	94	2	1.9519
57	94	2	1.4526
58	94	2	1.4526
57	94	1	2.0848
58	94	1	2.0848
59	94	1	5.5820
60	94	1	5.5820
61	94	1	5.9796
62	94	1	5.9796
63	94	1	3.7903
64	94	1	3.7903
65	94	1	4.9025

66	94	1	4.9025
67	94	1	2.4718
68	94	1	2.4718
67	94	1	1.1406
68	94	1	1.1406
69	94	1	2.7484
70	94	1	2.7484
71	94	1	0.1345
72	94	1	0.1345
71	94	2	0.4188
72	94	2	0.4188
71	94	3	0.0868
72	94	3	0.0868
71	94	4	0.0829
72	94	4	0.0829
73	94	2	2.6460
74	94	2	2.6460
75	94	2	3.9951
76	94	2	3.9951
75	94	2	0.4327
76	94	2	0.4327
77	94	2	3.0354
78	94	2	3.0354
79	94	2	0.0736
80	94	2	0.0736
79	94	2	3.7260
80	94	2	3.7260
81	94	2	4.6306
82	94	2	4.6306
83	94	2	3.9812
84	94	2	3.9812
83	94	1	0.7761
84	94	1	0.7761
85	94	1	3.4582
86	94	1	3.4582
87	94	1	5.7116
88	94	1	5.7116
89	94	1	0.0098
90	94	1	0.0098
89	94	1	4.5900
90	94	1	4.5900
91	94	1	7.5223
92	94	1	7.5223

CC
CC NAME OF THE WELL

*---- WELNAM
I498R
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX QTMIN   QTMAX

```
    0        0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW      IW      JW   IFLAG      RW    SWELL   IDIR   KFIRST   KLAST   IPRF
           4           29          7           3           0.25       0           4           1           1           0
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
90
CC
CC
*------IW       JW      KW
29          7           1           0.3939
30          7           1           0.3939
29          7           2           1.3930
30          7           2           1.3930
31          7           2           0.7581
32          7           2           0.7581
31          7           1           1.3296
32          7           1           1.3296
33          7           1           0.5379
34          7           1           0.5379
33          7           1           2.4830
34          7           1           2.4830
35          7           1           5.0912
36          7           1           5.0912
37          7           1           2.4860
38          7           1           2.4860
37          7           2           0.8162
38          7           2           0.8162
39          7           2           2.3178
40          7           2           2.3178
41          7           2           0.0408
42          7           2           0.0408
41          7           1           0.5576
42          7           1           0.5576
43          7           2           0.8972
44          7           2           0.8972
43          7           1           0.7289
44          7           1           0.7289
45          7           2           0.7001
46          7           2           0.7001
45          7           2           0.5964
46          7           2           0.5964
47          7           2           1.4055
48          7           2           1.4055
49          7           2           1.0480
50          7           2           1.0480
51          7           2           0.5813
52          7           2           0.5813
51          7           2           0.5559
52          7           2           0.5559
```

53	7	2	1.4800
54	7	2	1.4800
55	7	2	1.7077
56	7	2	1.7077
57	7	2	1.7903
58	7	2	1.7903
59	7	2	1.4383
60	7	2	1.4383
61	7	2	0.4683
62	7	2	0.4683
61	7	2	0.3887
62	7	2	0.3887
61	7	1	1.3616
62	7	1	1.3616
63	7	1	2.4278
64	7	1	2.4278
65	7	1	0.4117
66	7	1	0.4117
65	7	1	3.0041
66	7	1	3.0041
67	7	1	0.8205
68	7	1	0.8205
67	7	2	0.9301
68	7	2	0.9301
67	7	2	0.5774
68	7	2	0.5774
67	7	1	1.1155
68	7	1	1.1155
69	7	1	3.6519
70	7	1	3.6519
71	7	1	0.8761
72	7	1	0.8761
71	7	2	1.0155
72	7	2	1.0155
73	7	1	0.7061
74	7	1	0.7061
73	7	2	3.1860
74	7	2	3.1860
73	7	3	0.0389
74	7	3	0.0389
73	7	4	0.0126
74	7	4	0.0126
75	7	2	2.0746
76	7	2	2.0746
75	7	2	2.7242
76	7	2	2.7242
77	7	2	6.2157
78	7	2	6.2157
79	7	2	0.9905
80	7	2	0.9905

CC
CC NAME OF THE WELL

```
*---- WELNAM
I554
CC
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE

*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW     IW     JW   IFLAG     RW    SWELL   IDIR   KFIRST   KLAST   IPRF
         5      25      44      3      0.25     0       4       1       1       0
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
82
CC
CC
*----   IW     JW    KW
25      44      1       0.1215
26      44      1       0.1215
25      44      2       1.3909
26      44      2       1.3909
25      44      3       0.3785
26      44      3       0.3785
27      44      2       2.4325
28      44      2       2.4325
29      44      2       0.6622
30      44      2       0.6622
29      44      3       0.2160
30      44      3       0.2160
29      44      2       1.3301
30      44      2       1.3301
31      44      2       2.5533
32      44      2       2.5533
33      44      2       2.2980
34      44      2       2.2980
35      44      2       2.2289
36      44      2       2.2289
37      44      2       2.2253
38      44      2       2.2253
39      44      2       0.5137
40      44      2       0.5137
39      44      2       2.4029
40      44      2       2.4029
41      44      2       4.6518
42      44      2       4.6518
43      44      2       3.2183
44      44      2       3.2183
45      44      2       0.7660
46      44      2       0.7660
45      44      3       0.3428
46      44      3       0.3428
```

47	44	2	1.8694
48	44	2	1.8694
49	44	2	0.3667
50	44	2	0.3667
49	44	3	0.4393
50	44	3	0.4393
49	44	4	0.0252
50	44	4	0.0252
51	44	2	2.1208
52	44	2	2.1208
53	44	2	3.1555
54	44	2	3.1555
55	44	2	2.7446
56	44	2	2.7446
57	44	2	1.9920
58	44	2	1.9920
59	44	2	2.0515
60	44	2	2.0515
61	44	2	0.9135
62	44	2	0.9135
61	44	3	1.0594
62	44	3	1.0594
63	44	3	2.1118
64	44	3	2.1118
63	44	2	0.0019
64	44	2	0.0019
65	44	3	0.0076
66	44	3	0.0076
65	44	2	2.6930
66	44	2	2.6930
67	44	2	1.9630
68	44	2	1.9630
67	44	2	2.0895
68	44	2	2.0895
69	44	2	2.0279
70	44	2	2.0279
69	44	3	0.3490
70	44	3	0.3490
71	44	2	2.4617
72	44	2	2.4617
71	44	3	0.2765
72	44	3	0.2765
73	44	2	2.6600
74	44	2	2.6600
73	44	3	0.2307
74	44	3	0.2307
75	44	2	3.0010
76	44	2	3.0010

CC
CC NAME OF THE WELL

*---- WELNAM

```
I964
CC
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW     IW     JW   IFLAG     RW    SWELL   IDIR   KFIRST   KLAST   IPRF
          6          17         43         3          0.25      0          4          1          1          0
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
30
CC
CC
*-------IW     JW     KW
17        43        1          0.5176
18        43        1          0.5176
17        43        2          1.5897
18        43        2          1.5897
15        43        2          3.4664
16        43        2          3.4664
13        43        2          1.7084
14        43        2          1.7084
13        43        1          0.6196
14        43        1          0.6196
13        43        2          0.2495
14        43        2          0.2495
11        43        2          3.6391
12        43        2          3.6391
9         43        2          1.7638
10        43        2          1.7638
9         43        1          0.7683
10        43        1          0.7683
7         43        1          1.1586
8         43        1          1.1586
7         43        2          0.7117
8         43        2          0.7117
7         43        2          0.9115
8         43        2          0.9115
5         43        2          3.0597
6         43        2          3.0597
3         43        2          4.9458
4         43        2          4.9458
1         43        2          4.9246
2         43        2          4.9246
CC
CC NAME OF THE WELL

*---- WELNAM
I965
CC
```

```
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW     IW     JW   IFLAG     RW    SWELL   IDIR   KFIRST   KLAST   IPRF
          7          5          73         2          0.25      0          4          1          1          0
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
150
CC
CC
*-------IW     JW     KW
5          73         1          1.1209
6          73         1          1.1209
5          73         2          0.2816
6          73         2          0.2816
5          73         3          0.0664
6          73         3          0.0664
5          73         3          0.0627
6          73         3          0.0627
5          73         4          0.1001
6          73         4          0.1001
7          73         4          0.2021
8          73         4          0.2021
7          73         3          0.9836
8          73         3          0.9836
7          73         2          0.0648
8          73         2          0.0648
9          73         3          1.3885
10         73         3          1.3885
9          73         4          0.2554
10         73         4          0.2554
11         73         4          0.1004
12         73         4          0.1004
11         73         3          0.8629
12         73         3          0.8629
11         73         2          1.1663
12         73         2          1.1663
13         73         2          2.7260
14         73         2          2.7260
15         73         2          2.8576
16         73         2          2.8576
17         73         2          2.7949
18         73         2          2.7949
19         73         2          3.5542
20         73         2          3.5542
21         73         2          0.9032
22         73         2          0.9032
21         73         2          1.9140
22         73         2          1.9140
```

23	73	2	2.6950
24	73	2	2.6950
25	73	2	0.8048
26	73	2	0.8048
25	73	1	2.3887
26	73	1	2.3887
27	73	1	3.4886
28	73	1	3.4886
29	73	1	0.4458
30	73	1	0.4458
29	73	2	1.4456
30	73	2	1.4456
31	73	2	0.4116
32	73	2	0.4116
31	73	1	0.0341
32	73	1	0.0341
31	73	1	1.5937
32	73	1	1.5937
31	73	2	0.2047
32	73	2	0.2047
33	73	1	2.7024
34	73	1	2.7024
33	73	1	0.5936
34	73	1	0.5936
35	73	1	3.6571
36	73	1	3.6571
37	73	1	3.4043
38	73	1	3.4043
39	73	1	2.5486
40	73	1	2.5486
39	73	2	1.1978
40	73	2	1.1978
41	73	2	4.2567
42	73	2	4.2567
43	73	2	2.3705
44	73	2	2.3705
43	73	2	1.9396
44	73	2	1.9396
45	73	2	3.8878
46	73	2	3.8878
47	73	2	2.7090
48	73	2	2.7090
47	73	2	0.8076
48	73	2	0.8076
49	73	2	0.6194
50	73	2	0.6194
49	73	3	0.1524
50	73	3	0.1524
49	73	4	0.5720
50	73	4	0.5720
51	73	4	0.2005
52	73	4	0.2005

51	73	4	0.5977
52	73	4	0.5977
53	73	4	0.9155
54	73	4	0.9155
53	73	4	0.1915
54	73	4	0.1915
55	73	4	0.9826
56	73	4	0.9826
57	73	4	0.4108
58	73	4	0.4108
57	73	3	1.0757
58	73	3	1.0757
59	73	3	2.0543
60	73	3	2.0543
61	73	3	1.9877
62	73	3	1.9877
63	73	3	1.3590
64	73	3	1.3590
63	73	4	0.0932
64	73	4	0.0932
65	73	3	0.9174
66	73	3	0.9174
65	73	4	0.0062
66	73	4	0.0062
65	73	2	1.9732
66	73	2	1.9732
67	73	2	6.4880
68	73	2	6.4880
69	73	2	2.6442
70	73	2	2.6442
69	73	2	3.4620
70	73	2	3.4620
71	73	2	4.3771
72	73	2	4.3771
73	73	2	2.5978
74	73	2	2.5978
73	73	1	0.5319
74	73	1	0.5319
75	73	2	0.4367
76	73	2	0.4367
75	73	1	5.2059
76	73	1	5.2059
77	73	1	3.7517
78	73	1	3.7517
79	73	1	3.9382
80	73	1	3.9382
81	73	1	5.9902
82	73	1	5.9902
83	73	1	4.3115
84	73	1	4.3115
85	73	1	0.2095
86	73	1	0.2095

```
85          73          1           4.2660
86          73          1           4.2660
87          73          1           4.6794
88          73          1           4.6794
89          73          1           12.5636
90          73          1           12.5636
91          73          1           10.3727
92          73          1           10.3727
CC
CC NAME OF THE WELL
*---- WELNAM
Prod1182
CC
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0        0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW      IW      JW   IFLAG      RW    SWELL   IDIR   KFIRST   KLAST   IPRF
          8          11         23         2          0.25       0          4           1           1           0
CC
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
114
CC
CC
*-------IW      JW      KW
11          23          1           1.7925
12          23          1           1.7925
11          23          1           1.6437
12          23          1           1.6437
13          23          1           1.3287
14          23          1           1.3287
13          23          1           3.1799
14          23          1           3.1799
15          23          1           2.8468
16          23          1           2.8468
15          23          1           1.8211
16          23          1           1.8211
15          23          2           0.2078
16          23          2           0.2078
17          23          2           1.3382
18          23          2           1.3382
17          23          1           0.9292
18          23          1           0.9292
19          23          2           3.9838
20          23          2           3.9838
21          23          2           1.5759
22          23          2           1.5759
21          23          3           1.3210
22          23          3           1.3210
23          23          3           1.7381
```

24	23	3	1.7381
25	23	3	1.4759
26	23	3	1.4759
27	23	3	1.6301
28	23	3	1.6301
29	23	3	1.1195
30	23	3	1.1195
29	23	3	0.4704
30	23	3	0.4704
31	23	3	1.3794
32	23	3	1.3794
33	23	3	1.1017
34	23	3	1.1017
33	23	4	0.1634
34	23	4	0.1634
35	23	3	0.4938
36	23	3	0.4938
35	23	4	0.1816
36	23	4	0.1816
35	23	2	0.3513
36	23	2	0.3513
35	23	1	0.4253
36	23	1	0.4253
37	23	1	0.7291
38	23	1	0.7291
37	23	2	0.3040
38	23	2	0.3040
39	23	2	2.5934
40	23	2	2.5934
41	23	2	2.2455
42	23	2	2.2455
41	23	1	0.1645
42	23	1	0.1645
43	23	2	2.7559
44	23	2	2.7559
45	23	2	0.0200
46	23	2	0.0200
45	23	3	1.1547
46	23	3	1.1547
45	23	4	0.5037
46	23	4	0.5037
47	23	4	1.2911
48	23	4	1.2911
49	23	4	1.3561
50	23	4	1.3561
51	23	4	0.2751
52	23	4	0.2751
51	23	3	0.7456
52	23	3	0.7456
53	23	3	0.6771
54	23	3	0.6771
53	23	4	0.5652

```
54        23        4        0.5652
55        23        4        0.7481
56        23        4        0.7481
55        23        3        0.6499
56        23        3        0.6499
57        23        3        1.5766
58        23        3        1.5766
57        23        2        0.0296
58        23        2        0.0296
59        23        3        1.9628
60        23        3        1.9628
59        23        3        0.0214
60        23        3        0.0214
61        23        3        0.8618
62        23        3        0.8618
61        23        2        2.0204
62        23        2        2.0204
61        23        2        0.1635
62        23        2        0.1635
63        23        2        4.1911
64        23        2        4.1911
65        23        2        3.2537
66        23        2        3.2537
65        23        1        0.8542
66        23        1        0.8542
67        23        1        3.3570
68        23        1        3.3570
69        23        1        0.8945
70        23        1        0.8945
69        23        1        1.0384
70        23        1        1.0384
71        23        1        1.6504
72        23        1        1.6504
73        23        1        2.3345
74        23        1        2.3345
75        23        1        1.7137
76        23        1        1.7137
CC
CC NAME OF THE WELL

*---- WELNAM
P1188
CC
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       0.0     9000.   0.0     9000.
 CC
CC WELL LOCATIONS, FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN, PERF.
 *----  IDW      IW      JW   IFLAG      RW    SWELL   IDIR   KFIRST   KLAST   IPRF
          9        49       61        3         0.25      0         4          1          1          0
CC
```

```
CC For the Deviated Well, IPRF must be equal to Zero
*----NWBC
54
CC
CC
*-------IW    JW    KW
49    61    2    0.6194
50    61    2    0.6194
49    61    3    0.1524
50    61    3    0.1524
49    61    4    0.5720
50    61    4    0.5720
51    61    4    0.2005
52    61    4    0.2005
51    61    4    0.5977
52    61    4    0.5977
53    61    4    0.9155
54    61    4    0.9155
53    61    4    0.1915
54    61    4    0.1915
55    61    4    0.9826
56    61    4    0.9826
57    61    4    0.4108
58    61    4    0.4108
57    61    3    1.0757
58    61    3    1.0757
59    61    3    2.0543
60    61    3    2.0543
61    61    3    1.9877
62    61    3    1.9877
63    61    3    1.3590
64    61    3    1.3590
63    61    4    0.0932
64    61    4    0.0932
65    61    3    0.9174
66    61    3    0.9174
65    61    4    0.0062
66    61    4    0.0062
65    61    2    1.9732
66    61    2    1.9732
67    61    2    6.4880
68    61    2    6.4880
69    61    2    2.6442
70    61    2    2.6442
69    61    2    3.4620
70    61    2    3.4620
71    61    2    4.3771
72    61    2    4.3771
73    61    2    2.5978
74    61    2    2.5978
73    61    1    0.5319
74    61    1    0.5319
```

```
75        61        2         0.4367
76        61        2         0.4367
75        61        1         5.2059
76        61        1         5.2059
77        61        1         3.7517
78        61        1         3.7517
79        61        1         3.9382
80        61        1         3.9382
CC
CC NAME OF THE WELL
*---- WELNAM
PilotInj
CC
CC ICHEK  MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE

*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       0.0     9000.   0.0     9000.
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID        QIF       water     oil       surf      polymer Chlor     divalent  alc1      alc2 tracer1
        tracer2
        1         1922.5    1         0         0         0         0.0381    0.0115              0         0
        0         0
        1         0         0         0         0         0         0         0                   0         0
        0         0
        1         0         0         0         0         0         0         0                   0         0
        0         0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID     PWF
      1      6300
CC
CC 3.7.7b ID, RATE FOR RATE CONSTRAINT WELL (IFLAG=1 OR 4)
*----  ID     For IFLAG =4, specified RATE in CFD, negative for prodcution
      2      0
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID        QIF       water     oil       surf      polymer Chlor     divalent  alc1      alc2 tracer1
        tracer2
        3         2601.0    1         0         0         0         0.0381    0.0115              0         0
        0         10
        3         0         0         0         0         0         0         0                   0         0
        0         0
        3         0         0         0         0         0         0         0                   0         0
        0         0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID     PWF
      3      6100
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
```

```
 *----  ID        QI      water   oil     surf    polymer Chlor   divalent alc1   alc2 tracer1
        tracer2
        4         904.7   1       0       0       0       0.0381  0.0115          0       0
        0         0
        4         0       0       0       0       0       0       0               0       0
        0         0
        4         0       0       0       0       0       0       0               0       0
        0         0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID    PWF
    4     6000
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID        QI      water   oil     surf    polymer Chlor   divalent alc1   alc2 tracer1
        tracer2
        5         2827.2  1       0       0       0       0.0381  0.0115          0       0
        0         0
        5         0       0       0       0       0       0       0               0       0
        0         0
        5         0       0       0       0       0       0       0               0       0
        0         0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID    PWF
    5     5700
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID        QI      water   oil     surf    polymer Chlor   divalent alc1   alc2 tracer1
        tracer2   6       2092.1  1       0       0       0       0.0381  0.0115          0
        0         0       0
        6         0       0       0       0       0       0       0               0       0
        0         0
        6         0       0       0       0       0       0       0               0       0
        0         0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID    PWF
    6     5500
CC
CC 3.7.7b ID, PRES FOR PRES CONSTRAINT WELL (IFLAG=2)
*----  ID    PWF
    7    600
CC
CC 3.7.7b ID, PRES FOR PRES CONSTRAINT WELL (IFLAG=2)
*----  ID    PWF
    8    2300
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID        QI      water   oil     surf    polymer Chlor   divalent alc1   alc2 tracer1
        tracer2   9       1500    0.98    0       0.02    0.95    0.7875  0.0115          0
        0         0       0
```

```
          9         0         0         0         0         0         0         0                   0         0
          0         0
          9         0         0         0         0         0         0         0                   0         0
          0         0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID     PWF
     9      5000
CC 3.7.8 CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
CC         profilesPROF   prodPROF    prodHIST    maps      recovery
*---- TINJ    CUMPR1     CUMHI1            WRHPV            WRPRF  RSTC
          105        100        100        30          100        100
CC
CC 3.7.11 FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. courant numbers
*----  DT           DCLIM      CNMAX        CNMIN
     0.00001         10*0.01       0.2         0.03
CC*************************************************
CC FLAG FOR INDICATING BOUNDARY CHANGE
*---- IBMOD
      0
CC
CC  IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*----  IRO    ITIME     IFLAG
      2       1        3 4 3 3 3 3 2 2 3
CC
CC  NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----  NWEL1
      0
CC
CC  NUMBER OF WELLS WITH RATE CHANGES, ID only injectors
*---- NWEL2      id
      1    9
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID            QI         water     oil         surf       polymer Chlor     divalent  alc1       alc2 tracer1
          tracer2   9          1500      1           0           0           1.1         0.65       0.0115              0
          0           0          0
          9           0          0          0           0           0           0           0                   0           0
          0           0
          9           0          0          0           0           0           0           0                   0           0
          0           0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID     PWF
     9      5000
CC 3.7.8 CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
CC         profilesPROF   prodPROF    prodHIST    maps      recovery
*------ TINJ        CUMPR1           CUMHI1            WRHPV            WRPRF  RSTC
          2880      100        100        30          100        500
CC
CC 3.7.11 FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. courant numbers
*----  DT           DCLIM      CNMAX        CNMIN
```

```
     0.00001        10*0.01      0.2        0.03
CC*****************************************************
CC FLAG FOR INDICATING BOUNDARY CHANGE
*---- IBMOD
      0
CC
CC  IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*----  IRO    ITIME     IFLAG
      2       1       3 4 3 3 3 3 2 2 3
CC
CC  NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----  NWEL1
      0
CC
CC  NUMBER OF WELLS WITH RATE CHANGES, ID only injectors
*---- NWEL2      id
      1    9
CC
CC  3.7.7a ID,INJ. PRES AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
 *----  ID          QI        water     oil       surf      polymer Chlor     divalent  alc1      alc2 tracer1
          tracer2   9         1500      1         0         0         0         0.0381    0.0115              0
          0         0         0
          9         0         0         0         0         0         0         0                   0         0
          0         0
          9         0         0         0         0         0         0         0                   0         0
          0         0
CC
CC 3.7.7b ID, PRES FOR PRES. CONSTRAINT WELL (IFLAG=3)
*----  ID      PWF
     9      5000
CC 3.7.8 CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
CC         profilesPROF   prodPROF    prodHIST    maps      recovery
*------ TINJ        CUMPR1          CUMHI1          WRHPV           WRPRF  RSTC
          6000      100       100       30        100       500
CC
CC 3.7.11 FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. courant numbers
*----  DT           DCLIM      CNMAX       CNMIN
     0.00001        10*0.01      0.1        0.03
```

Appendix C: Input file for Base_2 simulation in Chapter 5

```
CC*******************************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET : UTCHEM2011                                  *
CC                                                                  *
CC*******************************************************************************
CC                                                                  *
CC                                                                                  *
CC                                                                  *
CC  LENGTH (FT) : 210 ft          PROCESS:ASP                              *
CC  THICKNESS (FT) : 150 ft        INJ. RATE (FT3/DAY) :                       *
CC  WIDTH (FT) : 180 ft           COORDINATES : CARTESIAN                       *
CC  POROSITY : variable           PROD. RATE (FT3/DAY):                       *
CC  GRID BLOCKS : 21x18x75         1BBL=5.615 cubic feet                       *
CC  DATE : 10/24/2011             Mangala Fine grid simulation              *
CC                                                                  *
CC*******************************************************************************
CC                          *
CC*******************************************************************************
CC                                                                  *
CC   RESERVOIR DESCRIPTION                                              *
CC                                                                  *
CC*******************************************************************************
CC
CC
*----RUNNO  (title)
MGL31c
CC
CC
*----HEADER  (need 3 lines)
MGL31c
Ref MGL31a. Increased PD drive size (15months,1.2PV total)
waterflood (8months) + polymer drive (5months) + ASP drive (5months) + Polymer Chase (15months) +
Water Chase (5months)
CC
CC SIMULATION FLAGS
*-------IMODE    IMES     IDISPC  ICWM   ICAP     IREACT          IBIO     ICOORD
        ITREAC            ITC      IGAS   ieng
        2        3        3        0      0        3        0      1        0        0        0
        0
CC
CC NUMBER OF GRID BLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
   21   18  75  2      0
CC
CC  CONSTANT GRID BLOCK SIZE IN X, Y, AND Z  (in ft)
*----DX
        21*32.8
CC
CC  CONSTANT GRID BLOCK SIZE IN X, Y, AND Z  (in ft)
```

```
*----DY
        18*32.8
CC
CC  CONSTANT GRID BLOCK SIZE IN X, Y, AND Z  (in ft)
*----DZ
        75*3.28
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*------ N no      NTw     nta     ngc     ng      noth
        12      0       0       0       4       0       0
CC
CC  All species must be present even for standard waterflood.
*---- species name
WATER
OIL
SURFACTANT
POLYMER
ANION
CALCIUM
alc1
alc2
CARBONATE
SODIUM
HYDROGEN
PET ACID
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  1  1  1  1  0  0  1  1  1  1
CC
CC*******************************************************************
CC                                   *
CC    OUTPUT OPTIONS                              *
CC                                   *
CC*******************************************************************
CC
CC
CC FLAG TO ECHO THE INPUT, FLAG TO WRITE TO UNIT 5, FLAG FOR PV OR DAYS
*----ICUMTM  ISTOP   IOUTGMS  IS3G
   0      0       0               0
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
   1  1  1  1  1  1  0  0  1  1  1  1  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPBIO IPCAP IPGEL IPALK IPTEMP IPOBS
    1     1     1     0     0     0    1     0             0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 6 (PROFIL)
*----ICKL IVIS IPER ICNM ICSE  IHYSTP   IFOAMP          INONEQ
    1   1    1    1    1     0       0        0
```

```
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 6 (PROFIL)
*----IADS  IVEL IRKF IPHSE
     1    0    1    1
CC
CC*******************************************************************
CC                                                   *
CC    RESERVOIR PROPERTIES                                       *
CC                                                   *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME
*----- TMAX (days)
           1140
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
     3.6e-6      1620
CC
CC  FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRANZ  INTG
      4      4     4      4      1      0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI  ICWI
     4        1       4    -1
CC
CC
*----IPRESS  DEPTH
    1304     2457.06
CC
CC FLAG FOR RESERVOIR PROPERTY MODIFICATION
*----IMPOR  IMKX  IMKY  IMKZ  IMSW
      0     0     0     0     0
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
   0.118091621    0.03391
CC
CC*******************************************************************
CC
CC PHYSICAL PROPERTY DATA
CC
CC*******************************************************************
CC
CC
CC OIL CONC. AT PLAIT POINT FOR TYPE II(+) AND TYPE II(-), CMC (do not change)
*---- C2PLC   C2PRC  EPSME    IHAND
     0.     1.     0.0001     0
CC
CC
```

```
*---- IFGHBN
      0
CC
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
*----   HBNS70    HBNC70              HBNS71              HBNC71              HBNS72              HBNC72
            0.          .08         0.          .025       0.0         .08
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
    0.    0.    0.    0.    0.    0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1(7) AND ALCOHOL 2 (8)
*----   CSEL7      CSEU7  CSEL8  CSEU8
            0.3         0.6         0.          0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
    0.0    0    0.0
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
    0    0.0     0     0.     0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
    20      .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1  (leave as is)
*----AKWC7   AKWS7  AKM7  AK7     PT7
    4.671    1.79   48   35.31  0.222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
    0.     0.     0.    0.     0.
CC
CC  0 = Healy and Reed and 1 is Chun-Huh
*--- ift
    1
CC
CC INTERFACIAL TENSION PARAMETERS
*----CHUH  AHUH
    0.3   10.
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
    1.146
CC
CC mass transfer flag
*----imass   ICOR
    0       0
cc
cc
```

```
*--- IWALT    IWALF
      0       0
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----   ITRAP       T11        T22        T33
       1    1865       59074     364.2
CC
CC relative perm. flag (0:imbibition corey,1:first drainage corey
*----iperm     IRTYPE
    0          1
CC
CC
*--- NREGION
     3
CC
CC S1RW(I), S2RW(I), S3RW(I), for I=1, NREGION AT LOW CAPILLARY NO.
*----S1RW(I) S2RW(I) S3RW(I)
    0.04  0.2         0.04
    0.04  0.075       0.04
    0.01  0.01        0.01
CC
CC P1RW(I), P2RW(I), P3RW(I), for I=1, NREGION AT LOW CAPILLARY NO.
*---- P1RW(I), P2RW(I), P3RW(I)
     0.6   0.93       0.6
     0.88  1          0.88
     1                1           1
CC
CC E1W(I), E2W(I), E3W(I), for I=1, NREGION AT LOW CAPILLARY NO.
*----E1W(I), E2W(I), E3W(I)
    2.36  4.0         2.36
    1.60  1.87        1.60
    1.00  1.00        1.00
CC
CC  RES. SATURATION OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----S1RC(=SWIR)  S2RC(=SORCHEM)  S3RC(SMER=SWIR)
    .0    .0    .0
CC
CC ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----P1RC P2RC P3RC
    1.    1.    1.
CC
CC REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----E13CW  E23C E31C
    1    1    1
CC
CC WATER AND OIL VISCOSITY at reference temperature, RESERVOIR TEMPERATURE (leave
zero)
*----VIS1   VIS2  TEMPV
    0.48    17     0.
CC
CC MICROEMULSION VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
```

```
          1           1           0.5         0.5         0.5
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1      AP2     AP3
          150         150         850
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SSLOPE
   1.   .01   -0.38
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN   IPMOD  ISHEAR   RWEFF  GAMHF2
          15          5           1.7         0           0           0.4         0.0
CC
CC FLAG FOR POLYMER (4) PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4   BRK    CRK    rkcut
          1           1           1           100         0.015       10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2  den23   DEN3 DEN7 DEN8 IDEN
   .44  .4065  0.4065   .42 .346  0.  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
    1
CC
CC  FVF FOR PHASE 1,2,3
*-----(FVF(L),L=1,NPHAS)
    1   1    1
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
       2.7e-6       4.96e-5        0        0        0
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----IOW
   0
CC
CC CPC(K,1,1), EPC(K,1,1), for K=1, NREGION
*----CPC            EPC
   0                2
   0                2
   0                2
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----   D(1)         D(2)       D(3)       D(4)       D(5)       D(6)       D(7)       D(8)       D(9)       D(10)     D(11)
          D(12)
          0           0           0           0           0           0           0           0           0           0           0
          0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
```

```
*----   D(1)          D(2)       D(3)       D(4)       D(5)       D(6)       D(7)       D(8)       D(9)       D(10)     D(11)
        D(12)
        0             0          0          0          0          0          0          0          0          0         0
        0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----   D(1)          D(2)       D(3)       D(4)       D(5)       D(6)       D(7)       D(8)       D(9)       D(10)     D(11)
        D(12)
        0             0          0          0          0          0          0          0          0          0         0
        0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY (ft) OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.02          0.00
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.02          0.00
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.02          0.00
CC
CC
*--- IADSO
   0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*---- AD31          AD32       B3D        AD41       AD42       B4D        IADK       IADS1      FADS       REFK
        1             0.1        1000       1.5        0.1        100        0          0          0          50
2  1   2800
7   13   13  0.1
 0.1    0.3
0
 5 10  0  2  0  1
 5  1  4  6
 3  2  0  0  1
 0  0  0
 4
CARBONATE                         -2.00
SODIUM                        1.00
HYDROGEN (REACTIVE)                1.00
Oleic acid                  -1.00
clorine  (* ELEMNT *)             -1.00
 HYDROGEN ION
 SODIUM ION
 CARBONATE ION
 HAo
 WATER
 A-
 OH-
 HCO3-
```

```
 H2CO3
 HAw  (* FLDSPS *)
 SORBED HYDROGEN ION
 SORBED SODIUM ION  (* SORBSPS *)
 2
 0.  0.  1.  0.  0.  0.  0.  1.  1.  0.
 0.  1.  0.  0.  0.  0.  0.  0.  0.  0.
 1.  0.  0.  1.  2.  0.  1.  1.  2.  1.
 0.  0.  0.  1.  0.  1.  0.  0.  0.  1.
 0.  0.
 0.  1.
 1.  0.
 0.  0.
 1.0  0.0  0.0  0.0  0.0  0.0  0.0
 0.0  1.0  0.0  0.0  0.0  0.0  0.0
 0.0  0.0  1.0  0.0  0.0  0.0  0.0
 0.0  0.0  0.0  1.0  0.0  0.0  0.0
 0.0  0.0  0.0  0.0  1.0  0.0  0.0
-1.0  0.0  0.0  1.0  0.0  0.0  0.0
-1.0  0.0  0.0  0.0  0.0  0.0  0.0
 1.0  0.0  1.0  0.0  0.0  0.0  0.0
 2.0  0.0  1.0  0.0  0.0  0.0  0.0
 0.0  0.0  0.0  1.0  0.0  0.0  0.0
 0.0  0.0  0.0  0.0  0.0  1.0  0.0
 0.0  0.0  0.0  0.0  0.0  0.0  1.0
 1.0  1.0 -2.0  0.0  0.0 -1.0 -1.0 -1.0  0.0  0.0
 1.0  1.0
0.1000000000000E+01 0.1000000000000E+01 0.1000000000000E+01
0.1000000000000E+01 0.1000000000000E+01 0.2228307914332E-11
0.1460000000000E-13 0.2110000000000E+11 0.4890000000000E+17
0.2228307914332E-03
0.2700000000000E+07
-1.0  1.0  0.0  0.0  0.0  1.0 -1.0
 0.0
0.2999997104553E-01
0.1180916210000E+00 0.0000000000000E+00
0.1422306000000E-01
0.1221639706677E+00
0.1109553256583E+03
0.1930299561788E-05
0.8401811938246E-02
0.3221393585557E-06 0.1221639706677E+00 0.5989828256250E-06
0.1952223570044E-01 0.5546282534568E+02
0.2630527711177E-01 0.3694693933769E-02
0.9999990348512E+00 0.9958166678160E+00
0.1000000000000E-07 0.5000000000000E+03
CC
CC*****************************************************************
CC
CC  WELL DATA
CC
CC*****************************************************************
```

```
CC
CC
CC flag for right and left boundary
*---- ibound   IZONE
     0        0
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWELR
     5      2     1     5
CC 4/10/2009
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG   RW     SWELL  IDIR  IFIRST   ILAST    IPRF
      1   10   8     2     0.26     0      3     1        75       0
CC
CC WELL NAME
*---- WELNAM
Prod
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       300.0    1300.0  0.0     14036.5
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     2   7    14    1       0.26     0      3      1       75       0
CC
CC WELL NAME
*---- WELNAM
Inj1
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0    100000
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     3   17    4    1       0.26     0      3      1       75       0
CC
CC WELL NAME
*---- WELNAM
Inj2
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       300.0      1300.   0.0    100000
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     4   15    14    1       0.26     0      3      1       75       0
CC
CC WELL NAME
*---- WELNAM
```

```
Inj3
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       300.0      1300.   0.0     100000
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     5   7    4    1       0.26     0      3       1       75        0
CC
CC WELL NAME
*---- WELNAM
Inj4
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
    0       300.0      1300.   0.0    100000
CC
CC   Pressure constrained producer
*----WELL ID   PWF
    1         1300
CC
CC   Rate constrained injector
*--  ID    QI(M,L) water    oil       surf      polymer anion     cation    alc1      alc2      carb      sodium
           hyd      petacid
    2       2106     1.        0.        0.        0.        0.08443 0         0.00001 0.00001 0.00434 0.08717
           111.1    0.00001
    2    0.0.        0.        0.        0.        0.        0.        0         0         0         0         0
           0
    2    0.0.        0.        0.        0.        0.        0.        0         0         0         0         0
           0
CC
CC   Rate constrained injector
*--  ID    QI(M,L) water    oil       surf      polymer anion     cation    alc1      alc2      carb      sodium
           hyd      petacid
    3       2106     1.        0.        0.        0.        0.08443 0         0.00001 0.00001 0.00434 0.08717
           111.1    0.00001
    3    0.0.        0.        0.        0.        0.        0.        0         0         0         0         0
           0
    3    0.0.        0.        0.        0.        0.        0.        0         0         0         0         0
           0
CC
CC   Rate constrained injector
*--  ID    QI(M,L) water    oil       surf      polymer anion     cation    alc1      alc2      carb      sodium
           hyd      petacid
    4       2106     1.        0.        0.        0.        0.08443 0         0.00001 0.00001 0.00434 0.08717
           111.1    0.00001
    4    0.0.        0.        0.        0.        0.        0.        0         0         0         0         0
           0
    4    0.0.        0.        0.        0.        0.        0.        0         0         0         0         0
           0
CC
```

```
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd     petacid
   5      2106    1.      0.       0.       0.      0.08443  0        0.00001  0.00001  0.00434  0.08717
          111.1   0.00001
   5   0.0.       0.      0.       0.       0.      0.       0        0        0        0        0
          0
   5   0.0.       0.      0.       0.       0.      0.       0        0        0        0        0
          0
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES (3.7.8)
*----TINJ     CUMPR1  CUMHI2  WRHPV(HIST) WRPRF(PLOT) RSTC
   240      5      5      5      30      30
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT            DCLIM     CNMAX   CNMIN
   0.00001       12*0.01       0.1     0.01
CC****************************************  INJECT PF
*********************************************************
CC FLAG FOR INDICATING BOUNDARY CHANGE
*---- IBMOD
     0
CC
CC  IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*----  IRO    ITIME     IFLAG
     2      1       2  1  1  1  1
CC
CC  NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----  NWEL1
      0
CC
CC  NUMBER OF WELLS WITH RATE CHANGES, ID
*---- NWEL2     ID
     4       2 3 4 5
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd     petacid
   2      2106    1.      0.       0.       0.2     0.08443  0        0.00001  0.00001  0.00434  0.08717
          111.1   0.00001
   2   0.0.       0.      0.       0.       0.      0.       0        0        0        0        0
          0
   2   0.0.       0.      0.       0.       0.      0.       0        0        0        0        0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd     petacid
   3      2106    1.      0.       0.       0.2     0.08443  0        0.00001  0.00001  0.00434  0.08717
          111.1   0.00001
   3   0.0.       0.      0.       0.       0.      0.       0        0        0        0        0
          0
```

```
    3   0.0.        0.       0.       0.       0.       0.       0        0        0        0        0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water    oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd      petacid
    4     2106     1.       0.       0.       0.2      0.08443  0        0.00001  0.00001  0.00434  0.08717
          111.1    0.00001
    4   0.0.        0.       0.       0.       0.       0.       0        0        0        0        0
          0
    4   0.0.        0.       0.       0.       0.       0.       0        0        0        0        0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water    oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd      petacid
    5     2106     1.       0.       0.       0.2      0.08443  0        0.00001  0.00001  0.00434  0.08717
          111.1    0.00001
    5   0.0.        0.       0.       0.       0.       0.       0        0        0        0        0
          0
    5   0.0.        0.       0.       0.       0.       0.       0        0        0        0        0
          0
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES (3.7.8)
*----TINJ     CUMPR1  CUMHI2  WRHPV(HIST) WRPRF(PLOT) RSTC
    390       5       5       5       30        30
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT           DCLIM     CNMAX   CNMIN
    0.00001       12*0.01      0.1     0.005
CC****************************************  INJECT ASP with 3%
Na2CO3**********************************************************
CC FLAG FOR INDICATING BOUNDARY CHANGE
*---- IBMOD
      0
CC
CC  IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*----  IRO    ITIME     IFLAG
      2      1       2  1  1  1  1
CC
CC  NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----  NWEL1
       0
CC
CC  NUMBER OF WELLS WITH RATE CHANGES, ID
*---- NWEL2     ID
      4       2 3 4 5
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water    oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd      petacid
```

```
    2      2106     0.997    0.        0.003    0.45     0.00166  0         0.00001  0.00001  0.56604  0.56769
           111.1    0.00001
    2      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
    2      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
CC
CC   Rate constrained injector
*--  ID    QI(M,L)  water    oil       surf     polymer  anion    cation    alc1     alc2     carb     sodium
           hyd      petacid
    3      2106     0.997    0.        0.003    0.45     0.00166  0         0.00001  0.00001  0.56604  0.56769
           111.1    0.00001
    3      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
    3      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
CC
CC   Rate constrained injector
*--  ID    QI(M,L)  water    oil       surf     polymer  anion    cation    alc1     alc2     carb     sodium
           hyd      petacid
    4      2106     0.997    0.        0.003    0.45     0.00166  0         0.00001  0.00001  0.56604  0.56769
           111.1    0.00001
    4      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
    4      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
CC
CC   Rate constrained injector
*--  ID    QI(M,L)  water    oil       surf     polymer  anion    cation    alc1     alc2     carb     sodium
           hyd      petacid
    5      2106     0.997    0.        0.003    0.45     0.00166  0         0.00001  0.00001  0.56604  0.56769
           111.1    0.00001
    5      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
    5      0.       0.       0.        0.       0.       0.       0.        0        0        0        0
           0        0
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES (3.7.8)
*----TINJ      CUMPR1  CUMHI2  WRHPV(HIST) WRPRF(PLOT) RSTC
    540       5        5       5        10          30
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT            DCLIM     CNMAX   CNMIN
    0.00001   12*0.001     0.1     0.005
CC****************************************  INJECT Polymer Chase
******************************************************
CC FLAG FOR INDICATING BOUNDARY CHANGE
*---- IBMOD
      0
CC
CC  IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*----  IRO    ITIME     IFLAG
```

```
      2       1        2  1  1  1  1
CC
CC  NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----  NWEL1
       0
CC
CC  NUMBER OF WELLS WITH RATE CHANGES, ID
*---- NWEL2     ID
      4        2 3 4 5
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil     surf    polymer anion   cation  alc1    alc2    carb    sodium
          hyd     petacid
    2     2106    1.      0.      0.      0.13    0.00166 0       0.00001 0.00001 0.00000 0.00166
          111.1   0.00001
    2   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
    2   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil     surf    polymer anion   cation  alc1    alc2    carb    sodium
          hyd     petacid
    3     2106    1.      0.      0.      0.13    0.00166 0       0.00001 0.00001 0.00000 0.00166
          111.1   0.00001
    3   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
    3   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil     surf    polymer anion   cation  alc1    alc2    carb    sodium
          hyd     petacid
    4     2106    1.      0.      0.      0.13    0.00166 0       0.00001 0.00001 0.00000 0.00166
          111.1   0.00001
    4   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
    4   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil     surf    polymer anion   cation  alc1    alc2    carb    sodium
          hyd     petacid
    5     2106    1.      0.      0.      0.13    0.00166 0       0.00001 0.00001 0.00000 0.00166
          111.1   0.00001
    5   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
    5   0.0.      0.      0.      0.      0.      0.      0       0       0       0       0
          0
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES (3.7.8)
*----TINJ      CUMPR1  CUMHI2  WRHPV(HIST) WRPRF(PLOT) RSTC
```

```
   990      5      5      5      10      30
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT              DCLIM  CNMAX          CNMIN
    0.00001      12*0.001    0.2       0.005
CC***************************************  INJECT Water Chase w/ unsoftened
brine*****************************************************
CC FLAG FOR INDICATING BOUNDARY CHANGE
*---- IBMOD
     0
CC
CC  IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*----  IRO    ITIME     IFLAG
     2      1       2  1  1  1  1
CC
CC  NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----  NWEL1
      0
CC
CC  NUMBER OF WELLS WITH RATE CHANGES, ID
*---- NWEL2     ID
     4       2 3 4 5
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd     petacid
    2     2106    1.      0.       0.       0.      0.08443 0        0.00001  0.00001  0.00434  0.08717
          111.1   0.00001
    2   0.0.      0.      0.       0.       0.      0.       0        0        0        0        0
          0
    2   0.0.      0.      0.       0.       0.      0.       0        0        0        0        0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd     petacid
    3     2106    1.      0.       0.       0.      0.08443 0        0.00001  0.00001  0.00434  0.08717
          111.1   0.00001
    3   0.0.      0.      0.       0.       0.      0.       0        0        0        0        0
          0
    3   0.0.      0.      0.       0.       0.      0.       0        0        0        0        0
          0
CC
CC   Rate constrained injector
*--  ID   QI(M,L) water   oil      surf     polymer anion    cation   alc1     alc2     carb     sodium
          hyd     petacid
    4     2106    1.      0.       0.       0.      0.08443 0        0.00001  0.00001  0.00434  0.08717
          111.1   0.00001
    4   0.0.      0.      0.       0.       0.      0.       0        0        0        0        0
          0
    4   0.0.      0.      0.       0.       0.      0.       0        0        0        0        0
          0
```

CC
CC   Rate constrained injector
*-- ID   QI(M,L) water   oil   surf   polymer anion   cation   alc1   alc2   carb   sodium
hyd   petacid
5   2106   1.   0.   0.   0.   0.08443 0   0.00001 0.00001 0.00434 0.08717
111.1   0.00001
5   0. 0.   0.   0.   0.   0.   0.   0   0   0   0   0
0
5   0. 0.   0.   0.   0.   0.   0.   0   0   0   0   0
0
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES (3.7.8)
*----TINJ   CUMPR1 CUMHI2 WRHPV(HIST) WRPRF(PLOT) RSTC
1140   5   5   5   10   30
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT   DCLIM   CNMAX   CNMIN
0.00001   12*0.01   0.4   0.01

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